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VERIFIED DIRECT TESTIMONY OF CHARLES A. VAMOS

INTRODUCTION

Q1. Please state your name, business address, and job title.

A1. My name is Charles A. Vamos. My business address is 801 E. 86th Avenue, Merrillville, Indiana 46410. I am Director, Electric T&D (Transmission and Distribution) Engineering for Northern Indiana Public Service Company LLC ("NIPSCO" or "Company").

Q2. Please briefly describe your educational and business experience.

A2. I received a Bachelor of Science degree in Electric Engineering Technology from Purdue University in Hammond, Indiana in 1992. I received an M.B.A. from Indiana University in Gary, Indiana in 1996 and an M.S. in Electricity Markets from the Illinois Institute of Technology in Chicago, Illinois in 2010. I am a Registered Professional Engineer in the State of Indiana (2000) and a certified Project Management Professional (2012). I began my employment with NIPSCO in 1993 and have more than 25 years' experience in electric generation, transmission, and distribution as follows: Electrical Engineer (1993-2000), Asset Manager (2000-2003), Manager Electric Substations (2003-2011), Manager Electric Engineering (2011-2014), Manager Electric Asset Management (2014-2018) and Director, Electric T&D Engineering (2018 to present).

Q3. What are your responsibilities as Director of Electric T&D Engineering?

A3. As Director of Electric T&D Engineering, I am responsible for directing the Transmission and Distribution Engineering functions for NIPSCO's line, substation, and protective relaying groups. I currently oversee NIPSCO engineering departments to ensure the safe, reliable, and constructible designs for over $200 million in transmission and distribution projects yearly.

Q4. What are your responsibilities with respect to NIPSCO's electric TDSIC projects?

A4. I was responsible for development of NIPSCO's Electric TDSIC Plan for the period January 2016 through December 2022 ("Electric Plan 1")[1] including the development of detailed asset registers defining the projects included in Electric Plan 1. This responsibility also includes maintaining the risk model and updates to the condition-based assessment of assets in the

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[1] NIPSCO's Electric Plan 1 is set to expire December 31, 2022. In accordance with Ind. Code § 8-1-39-10(d), NIPSCO provided the Commission with a notice on April 1, 2021 that Electric Plan 1 will terminate on May 31, 2021.

Electric Plan 1 and making future updates as appropriate. I was also responsible for developing the project cost estimates and supporting the financial performance of the projects included in Electric Plan 1. I have been responsible for coordinating the preparation of NIPSCO's Electric TDSIC Plan for the period June 1, 2021 through December 31, 2026 (the "2021-2026 Electric Plan" or "Plan"), attached hereto as <u>Confidential Attachment 2-A</u>. In that role, I have worked with engineers under my supervision, including those in a consulting role, as well as with others within the Company to compile, review, prioritize and analyze projects for incorporation into the Plan.

Q5. Have you previously testified before this or any other regulatory commission?

A5. Yes. I previously submitted testimony before the Indiana Utility Regulatory Commission ("Commission") in NIPSCO's electric TDSIC tracker filings in Cause Nos. 44733-TDSIC-X (beginning in TDSIC-4).

Q6. What is the purpose of your direct testimony in this proceeding?

A6. The purpose of my direct testimony is to (1) provide a summary of the 2021-2026 Electric Plan, (2) explain how NIPSCO developed its 2021-2026 Electric Plan, (3) explain the reduction of risks after executing Electric Plan 1, (4) explain the proposed plan update process; (5) explain the cost estimates associated with the 2021-2026 Electric Plan, (6) discuss contingency as a component of estimating, (7) explain the various components of projects included in the 2021-2026 Electric Plan, (8) discuss NIPSCO's proposed execution of the 2021-2026 Electric Plan, (9) explain why the 2021-2026 Electric Plan constitutes eligible transmission, distribution, and storage system improvements ("eligible improvements"),[2] including the expected benefits from certain projects.

Q7. Are you sponsoring any attachments to your direct testimony?

A7. Yes. I am sponsoring the following documents, all of which were prepared by me or under my direction and supervision.

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[2] "'Eligible transmission, distribution, and storage system improvements' means new or replacement electric or gas transmission, distribution, or storage utility projects that: (1) a public utility undertakes for purposes of safety, reliability, grid modernization, or economic development, including the extension of gas service to rural areas; (2) were not included in the public utility's rate base in its most recent general rate case; and (3) either were (A) described in the public utility's TDSIC plan and approved by the commission under section 10 of this chapter and authorized for TDSIC treatment; (B) described in the public utility's update to the public utility's TDSIC plan under section 9 of this chapter and authorized for TDSIC treatment by the commission; or (C) approved as a targeted economic development project under section 11 of this chapter. The term includes (1) projects that do not include specific locations or an exact number of inspections, repairs, or replacements, including inspection based projects such as pole or pipe inspection projects, and pipe or pipe replacement projects; and (2) projects involving advanced technology investments to support the modernization of a transmission, distribution, or storage system, such as advanced metering infrastructure, information technology systems, or distributed energy resource management systems." Ind. Code § 8-1-39-2.

Attachment No.	Description
Confidential Attachment 2-A	NIPSCO's 2021-2026 Electric Plan
Confidential Attachment 2-B	2021–2026 TDSIC Investment Plan Business Case dated May 2021 prepared by Sargent & Lundy
Confidential Attachment 2-C	2021-2026 TDSIC Investment Plan Cost Analysis dated May 2021 prepared by Sargent & Lundy
Attachment 2-D	NIPSCO's Transmission Planning System Assessment Methodology and Planning Criteria dated January 14, 2021
Confidential Attachment 2-E	Distribution Automation Program Business Case dated April 2020 prepared by Leidos Engineering, LLC
Confidential Attachment 2-F	Long-Term Communications Plan dated May 2021 prepared by Sargent & Lundy
Attachment 2-G	Execution and Management of the Plan

Q8. Please describe the reports prepared by Sargent & Lundy.

A8. Sargent & Lundy, L.L.C. ("S&L") prepared four reports: (1) 2021–2026 TDSIC Investment Plan Business Case ("Long-Term Investment Plan"), which is attached hereto as Confidential Attachment 2-B; (2) 2021–2026 TDSIC Investment Plan Cost Analysis, which is attached hereto as Confidential Attachment 2-C; (3) Long-Term Communications Plan, which is attached hereto as Confidential Attachment 2-F; and (4) Economic Impacts of Projected NIPSCO T&D Expenditures, 2021–2026 ("Economic

Impact Report"), which is sponsored by Witness Becker as Confidential Attachment 1-D.

Q9. Please explain the Long-Term Investment Plan (Confidential Attachment 2-B).

A9. The Long-Term Investment Plan explains the three main objectives of NIPSCO's 2021-2026 Electric Plan: (1) maintaining safe and reliable performance while proactively replacing aging, high risk equipment across the system; (2) maintaining adequate system capacity to reliably serve customer loads; and (3) modernizing NIPSCO's electric grid with technologies that support improved reliability, asset health and condition, and preparing for future customer expectations.

To develop this document, NIPSCO (with support from S&L) outlined the long term plan to address aging assets and documented NIPSCO's risk-based approach to evaluating its transmission and distribution system. That approach is used to focus long term capital investment (and, by extension, TDSIC funds) towards the highest-risk assets on the system. These capital investments also include a one-time recouping of the operation and maintenance ("O&M") expenses associated with the installation of advanced metering infrastructure ("AMI").

The Long-Term Investment Plan includes three appendices: (1) Confidential Appendix A, which provides the NIPSCO T&D Risk Model Results ("TDSIC Risk Model"), (2) Confidential Appendix B, which provides the NIPSCO Effective Age Methodology; and (3) Confidential Appendix C, which provides the 2021-2026 NIPSCO Electric AMI Business Case developed by West Monroe Partners.

The Long-Term Investment Plan was developed through the process of evaluating risk-based projects, programmatic minor asset projects, deliverability-based projects, and strategic grid modernization initiatives to support customer experience and system reliability.

The first process is evaluating risk-based projects in the Long-Term Investment Plan. This approach prioritizes the major assets that should be included in the 2021-2026 project portfolio based on the consequence of an asset failing and likelihood of an asset failing. Through the proactive replacing of the highest risk assets, the overall risk of failure is reduced, as compared to simply replacing assets as they deteriorate and fail.[3] This

[3] Replacing assets as they fail is sometimes referred to as a "break/fix" approach to asset replacement.

dynamic risk assessment considers age, condition, and prioritization of assets that are approaching or have met end of life. Additionally, programmatic minor asset projects[4] are included in the category of Aging Infrastructure. Like major equipment, minor assets are vital to the safe and reliable operation of the electric system. These assets include annunciators, arresters, protective relays, insulators, line and substation switches, potential transformers, steel structures, substation batteries and chargers, substation capacitors, and wood poles. While these minor assets are critical, they are not assigned a risk score within the Long-Term Investment Plan. The increased quantity included through the electrical system would make assigning these individual assets a risk score overly burdensome. Instead, the aged and/or damaged minor assets go through inspection and analysis processes that result in either mitigation or replacement. These investments make up approximately 54% of the capital expenditures included in the 2021-2026 Electric Plan.

The second process is focused on increasing the deliverability of power to meet customer load, which in turn maintains and improves reliability for

[4] "Major equipment" and "minor asset" are accounting terms. Reference to an asset or asset category as minor or major does not imply it is more or less important to NIPSCO's system.

customers, especially when load grows. These projects increase the system's ability to provide power to increasing customer demand, as well as providing versatility as load demands become more diverse. These investments make up approximately 20% of the capital expenditures included in the 2021-2026 Electric Plan.

The third process is deploying strategic grid modernization initiatives to enhance customer service, improve reliability, and enable new technologies to improve NIPSCO's ability to meet customers' evolving operability expectations. The technologies proposed are AMI, intelligent sensing equipment (i.e., substation automation ("SA") and distribution automation ("DA") technologies), a distribution supervisory control and data acquisition ("DSCADA") system, as well as the inclusion of communication and telecommunication infrastructure. The implementation of AMI, DA, SA, DSCADA, and communication and telecommunication infrastructure systems will together increase reliability and functionality, both of which are directly realized by NIPSCO's customers. These investments make up approximately 26% of the expenditures included in the 2021-2026 Electric Plan.

The process of evaluating and prioritizing the implementation of DA investments is detailed in the Distribution Automation Program Business Case (Confidential Attachment 2-E). The report details the methodology in developing an economical implementation plan that maximizes benefits to NIPSCO's customers.

Communications is the backbone of grid modernization functions, as it provides a network for grid modernization technologies to increase system visibility. NIPSCO (with the assistance of S&L) developed the Long-Term Communications Plan (Confidential Attachment 2-F), which details the methodology to migrate NIPSCO's antiquated system to a new, more robust, and modern network.

Q10. Please explain how the 2021-2026 Electric Plan is presented and organized.

A10. The 2021-2026 Electric Plan is presented and organized as follows:

Plan by Project Category	Provides a high level summary showing the breakout of investment by year for both transmission and distribution.
Plan by FERC Account	Provides a high level summary showing the breakout of investment by year for both transmission and distribution by Federal Energy Regulatory Commission

	("FERC") Uniform System of Account account number.
Project Detail by Year	Provides project detail separately for each year of the Plan (2021-2026). Each line item shows the Project ID, the project category, the driver associated with the project, the project title, and the anticipated investment for each project (in direct dollars). Detailed scopes and estimate summaries (project estimates) are provided for Year 1 (2021) and Year 2 (2022).
Project Detail Summary by Year	Matrix showing all of the projects included in the Plan by project category by year showing the total investment for each project (in direct dollars).
Confidential Appendix A	Asset Register for Risk Based Projects
Confidential Appendix B	Asset Register for Non Risk Based Projects
Confidential Appendix C	Year 1 (2021) Project Estimates
Confidential Appendix D	Year 2 (2022) Project Estimates

SUMMARY OF NIPSCO'S 2021-2026 ELECTRIC PLAN

Q11. Please explain how NIPSCO's 2021-2026 Electric Plan fits into its overall strategy to invest in its system.

A11. The capital investment in NIPSCO's 2021-2026 Electric Plan is one of many components within its overall investment strategy. Other components include annual capital maintenance work, generation investments and transition, public improvement projects, as well as investments related to new business. As further explained below, the investments included in the 2021-2026 Electric Plan focus primarily on making necessary investments to enable NIPSCO to continue to provide safe, reliable electric service to its customers, as well as driving necessary grid modernization and deliverability advancements to meet evolving customer expectations and load.

Q12. Is the 2021-2026 Electric Plan NIPSCO's first TDSIC plan?

A12. No. Following passage of the TDSIC Statute by the Indiana General Assembly,[5] NIPSCO implemented Electric Plan 1 (for the period January 1, 2016 through December 31, 2022), which was approved by the Commission on July 12, 2016 in Cause No. 44733. The approved total capital expenditures under the Electric Plan 1 was approximately $1.25 billion. On April 1, 2021, NIPSCO filed a notice to terminate the Electric Plan 1 effective May 31, 2021.

Q13. What has NIPSCO accomplished through its investments under Electric Plan 1?

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[5] Ind. Code Ch. 8-1-39 (Transmission, Distribution, and Storage System Improvement Charges and Deferrals) was enacted as part of Senate Enrolled Act 560 and became effective on April 30, 2013, which was amended in House Enrolled Act No. 1470 and became effective on April 24, 2019 (the "TDSIC Statute").

A13. Through January 31, 2021, NIPSCO had invested approximately $781 million. NIPSCO focused its investment on proactively replacing aging, high risk equipment across its electric system. Some of the highlights include:[6]

- Power Transformers Replaced - 33
- Breakers Replaced - 319
- Protective Relays Upgrade Projects - 47
- Miles of Circuit Rebuilt – 564
- Miles of Underground Cable Replaced – 190 Miles
- Number of Line Transformers Replaced – 2,029
- Number of Switches Replaced – 389
- Complete update of all 4 kV distribution circuits to 12 kV

Initial projections estimated a 30% risk reduction if all projects under Electric Plan 1 were executed through 2022. In actuality, through five-and-a-half years of work, NIPSCO has realized a 21% risk reduction when compared to a "break/fix" replacement strategy. This is a significant accomplishment, which demonstrates the efficacy of NIPSCO's proactive replacement and capital investment strategy.

[6] These are estimated statistics as of February, 2021.

Q14. Please explain why NIPSCO decided to terminate Electric Plan 1 and file the 2021-2026 Electric Plan.

A14. After careful consideration, NIPSCO decided to file a new TDSIC plan for several reasons. Electric Plan 1 was successful in reducing system risk by replacing aged assets and addressing changing system demands. However, the projects originally identified in 2016 for potential execution in 2021 and 2022 required reprioritizing to NIPSCO's most recent system loading and condition information. The asset registers developed for Electric Plan 1 were developed as a snapshot in time prior to the filing and do not account for changing asset health or changes in electric demand. For example, a transformer may have been in perfect health when the plan was created, but a car hitting a nearby pole after the plan was filed could subject the same transformer to detrimental fault currents and damage it to the point where it needs replacement. Similarly, NIPSCO has realized an unexpected, sudden increase in electric demand in the eastern part of its service territory caused by the recent increase in new manufacturing facilities. While local manufacturing expansion and load growth are positive developments for NIPSCO and the State of Indiana, this presents challenges for NIPSCO as it plans to address current and future load growth. NIPSCO will also be pursuing grid modernization efforts that were not previously included in Electric Plan 1.

Additionally, the TDSIC Statute as it existed in 2016 (as interpreted by the Commission and courts) and the settlement agreement NIPSCO executed for the Electric Plan 1 did not allow for the addition of new projects. However, an amendment to the TDSIC Statute has expanded the categories of allowable TDSIC projects. All of this in combination led NIPSCO to the decision to terminate its Electric Plan 1 and develop and file the 2021-2026 Electric Plan, a plan that proposes projects based upon a more updated view of NIPSCO's electric system and projects that will enable NIPSCO to modernize its system to provide the service its customers expect and deserve.

Q15. Does the 2021-2026 Electric Plan require flexibility in its project portfolio?

A15. Yes. NIPSCO will require the ability to move projects already within the plan timeline, as well as remove, adjust, or add projects. NIPSCO will provide details on any updates to its Plan in its tracker filings.

Q16. Please provide a summary of NIPSCO's 2021-2026 Electric Plan.

A16. NIPSCO's 2021-2026 Electric Plan is focused on electric transmission and distribution system investments made to enhance system safety and reliability, modernize its system, and improve the customer experience. The Plan also makes provision for appropriate economic development projects in the future, although none are proposed at this time. The Plan is comprised of four main segments: (1) investments that target replacement of aging assets (Aging Infrastructure), (2) investments intended to maintain the capability of NIPSCO's electric system to deliver power to customers when they need it (System Deliverability), (3) investments for modernization of NIPSCO's electric system to deliver safe and reliable service, including installation of AMI (Grid Modernization),[7] and (4) eligible economic development projects in the future (Economic Development). Table 1 summarizes the 2021-2026 Electric Plan by investment segment.

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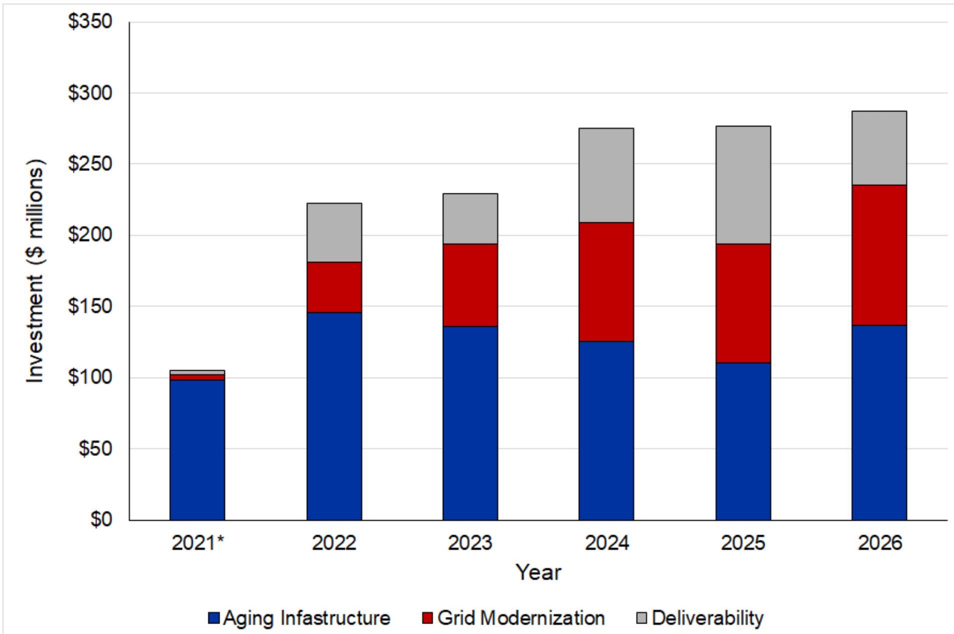
[7] The AMI investments are discussed by Witness Holtz.

Figure 1 – Investment Plan Spending by Segment and Year



*2021 investment only includes projects associated with the 2021-2026 Electric Plan. The 2021 investments associated with Electric Plan 1 are not included here.

Figure 2 – Potential Investment Spread

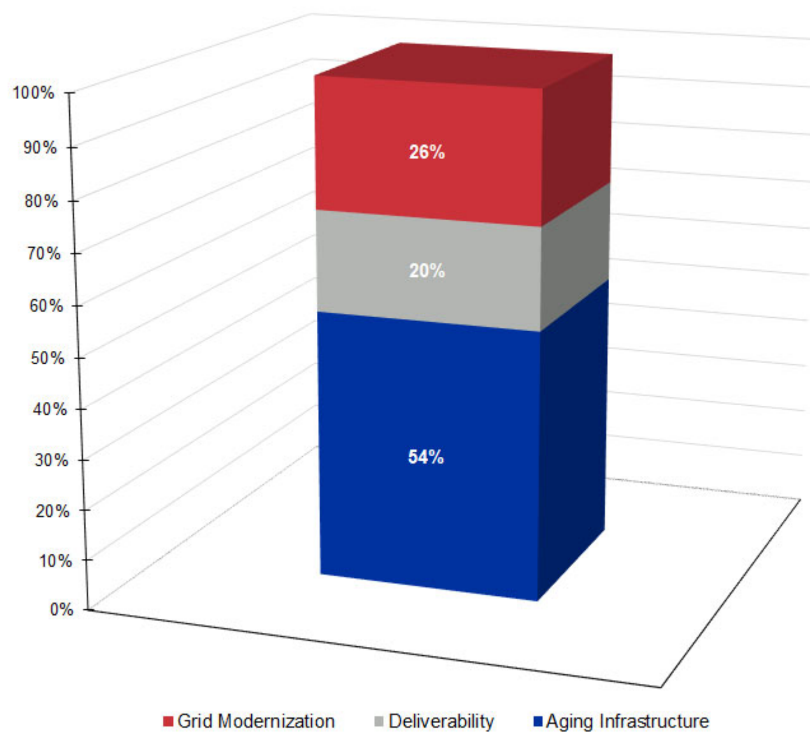


Table 1 – Investment by Segment

Investment Segment	**2021-2026 Electric Plan Projected Investment (Direct Capital Dollars)**
Aging Infrastructure	$753,121,380
System Deliverability	$281,439,419
Grid Modernization	$362,054,616
Economic Development	$0
Plan Total	**$1,396,615,415**

<u>DEVELOPMENT OF THE 2021-2026 ELECTRIC PLAN</u>

Q17. What is the primary goal of NIPSCO's 2021-2026 Electric Plan?

A17. The primary goal of the Plan is to deploy a portfolio of investments in electric transmission and distribution facilities that preserves NIPSCO's ability to serve peak load, maintain system performance, ensure the safety of NIPSCO's systems, and enable evolving energy technologies, such as Distributed Energy Resources ("DERs") and electric vehicles ("EVs"). The portfolio of investments serves these goals by replacing aging assets, increasing system deliverability, and modernizing the system for future growth.

Within the four (4) categories (safety, reliability, grid modernization, and economic development), the Plan is estimated to reduce the overall system risk, increase the deliverability of electric service, and enhance system automation to reduce customer outages and enable asset condition visibility.

Q18. Please describe the assets reviewed in developing the 2021-2026 Electric Plan.

A18. In developing the 2021-2026 Electric Plan, NIPSCO focused its review to all of its electric transmission and distribution assets. The NIPSCO electric transmission system consists of approximately 21 circuit miles of 765 kV; 453 circuit miles of 345 kV; 810 circuit miles of 138 kV; and 1,679 circuit miles of 69 kV transmission lines. In addition, NIPSCO has 66 transmission substations. NIPSCO serves approximately 470,000 electric customers in Northern Indiana, primarily through more than 900 distribution circuits. These circuits operate at a nominal voltage of 34.5 kV and 12.5 kV,[8] and radiate from approximately 249 distribution substations. There are approximately 7,903 miles of overhead line, with about 2,592 miles of underground cable. NIPSCO's review included all substation transformers, circuit breakers, system protection devices, and other ancillary substation equipment in its transmission, sub-transmission, and distribution substations, including the structures and the corresponding

[8] As part of Electric Plan 1, NIPSCO successfully replaced all 4 kV distribution circuits.

overhead and underground conductors associated with the transmission, sub-transmission, and distribution circuits. In this review, NIPSCO confirmed the following key facts about its electric transmission and distribution infrastructure:

- NIPSCO owns, operates, manages and controls transmission and distribution plant and equipment within the State of Indiana that is in service and used and useful in the furnishing of electric service to the public. NIPSCO has maintained and continues to maintain its properties in a reliable state of operating conditions.
- NIPSCO's electric system grew significantly during the 1960s and 1970s. Many assets installed during this era and before are reaching the end of their useful lives, and in many cases these assets are comprised of 1950s technology. These assets have increasing failure probabilities that will cause reliability degradation. This statistical likelihood of failure ("LOF") is increasing every day. Prior to the start of Electric Plan 1, NIPSCO began to experience increased asset failures due to deterioration. As discussed above, that plan began addressing aged major assets and minor programmatic asset projects, and the currently proposed Plan aims to continue this effort as assets continue to age and older technologies need to be replaced through grid modernization.
- There are certain asset segments that are demonstrating specific failure trends or unique reliability concerns, including a population of unjacketed underground cable that is approximately 40-50 years old. These circuits are geographically isolated with limited contingency in the event of failure.
- Some of NIPSCO's system protection devices are outdated and cannot protect the electric system and key assets in the manner consistent with modern standards.

- Ongoing investments will be required to ensure the electric system can continue to reliably deliver electric service to NIPSCO customers during periods of peak demand.

Q19. Why did NIPSCO select the transmission and distribution system improvements included in the 2021-2026 Electric Plan?

A19. The 2021-2026 Electric Plan was developed to address risks identified and prioritized as of early 2021, and as such, the 2021-2026 Electric Plan represents the current best path forward to ensure the continued delivery of safe and reliable electric service to NIPSCO's customers. The 2021-2026 Electric Plan builds on the capital investments prioritized in Electric Plan 1. Additionally, the Plan addresses identified areas of needed modernization. In considering Plan design, NIPSCO conducted comprehensive reviews of many segments of its electric system. The Plan addresses high priority safety and operational and integrity needs. Projects were also reviewed to provide a high level of confidence that they could be executed as proposed. A broader portfolio of projects was prioritized to develop the specific improvements included in the Plan, and plan for executions in a logical and efficient manner.

The transmission and distribution system investments included in the 2021-2026 Electric Plan are required for maintaining and improving the existing NIPSCO electrical portfolio. The Plan addresses safety, reliability, grid modernization, and allows for future economic development, all providing incremental benefits for NIPSCO's customers.

<u>RISK REDUCTION</u>

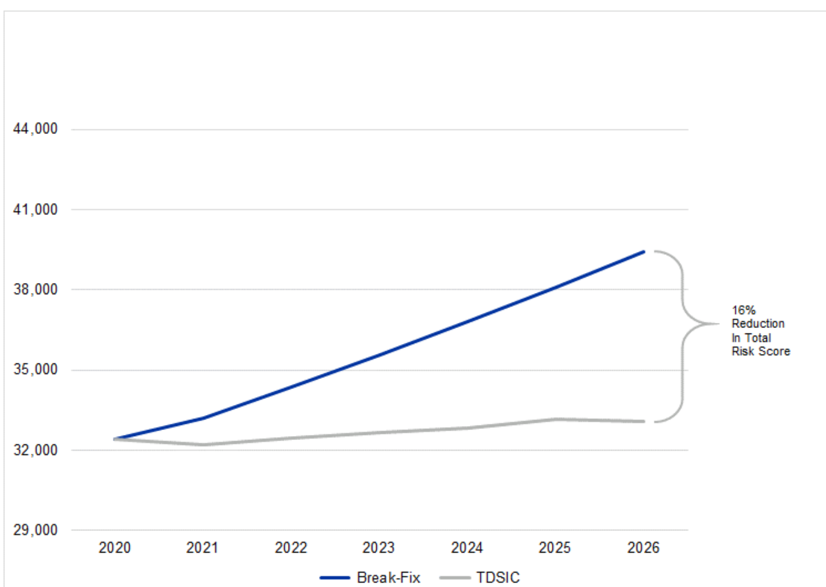
Q20. Did NIPSCO achieve reduction in risk through completion of the projects in Electric Plan 1?

A20. Yes. Based on the TDSIC Risk Model for major assets utilized in Electric Plan 1, the TDSIC electric projects completed from 2016 through 2020 reduced the relative NIPSCO system risk by 21% from the 2016 baseline. For comparison purposes only, had those projects not been completed, the NIPSCO system risk would have *increased* 19% from the 2016 baseline (assuming no other work was performed during that period).

Q21. What are NIPSCO's expectations for risk reductions under the 2021-2026 Electric Plan?

A21. One of the primary goals of the Plan is to reduce the overall system risk associated with aging asset populations and asset failures. NIPSCO acknowledges that the proposed investment levels in this Plan are substantial, but, even with the 21% risk reduction realized under Electric Plan 1, which is discussed above, there are still many older, aging assets on NIPSCO's system that need to be replaced before they fail. When comparing the proactive replacement strategy under TDSIC to a "break/fix" strategy, based on the TDSIC Risk Model, NIPSCO estimates an overall risk reduction of approximately 16%, as illustrated in Figure 3 below. Even with the investments made under Electric Plan 1, there is an opportunity for further investment under the 2021-2026 Electric Plan to continue to reduce risk, thereby increasing system reliability and better serve NIPSCO's customers.

Figure 3 – Risk Score for TDSIC Plan versus Break/Fix Strategy



Q22. What does the 16% risk reduction represent and are these results similar to those within Electric Plan 1?

A22. The 16% represents a projection of the reduced risk score calculated for the specific major asset(s), (i.e., transformers, breakers, circuits), but does not necessarily represent a percentage reduction in the likelihood of an issue with the asset(s). For example, the Goshen Junction Substation Rebuild project (Project ID TSNRS12), which includes both transformer and breaker replacements, will reduce the risk score associated with the current substation assets. However, it does not mean that the replacement of the existing asset will eliminate all risk associated with the new substation. There are multiple reasons for the variance between the 21% realized risk reduction under Electric Plan 1 and the estimated 16% risk reduction under this Plan; however, two factors drive the majority of the difference. The first reason is that the initial assets addressed in Electric Plan 1 were of higher impact, because there were the highest risk assets of the whole NIPSCO asset population, including the assets being replaced under this Plan. The second reason is driven by lessons learned by NIPSCO as it executed Electric Plan 1. Under this approach, NIPSCO has identified the opportunity to replace some assets that are just as old as targeted assets of the project in the same substation or the same circuit. These other assets have a finite life and will be required to be replaced in the near future. The most cost effective and least interruptive method to address all of the related assets in the Plan is to perform all of that work at the same time. For example, a typical substation includes circuit breakers for the lines entering and leaving the station, as well breakers for connecting the buses during maintenance. The line breakers are subject to harsher operating conditions than the bus breakers. Under Electric Plan 1, there were instances where just the line breakers were replaced, leaving the older bus breakers in service. Under the Plan, all the breakers at the substation would be replaced. NIPSCO's approach in this Plan is to take a more holistic approach to replacing aged assets on its system and replace them at the same time as the higher risk assets since resources are already deployed and outages are taken. Although this method is a more cost-effective and reliable method for customers in the long run, it also means that NIPSCO will be replacing some lower risk assets in conjunction with the higher risk assets identified through the TDSIC Risk Model.

Q23. Does NIPSCO anticipate that the 2021-2026 Electric Plan will change over the plan period?

A23. As stated above, the 2021-2026 Electric Plan was developed to address risks identified and prioritized as of early 2021, and, as such, the Plan represents the current best path forward to ensure the continued delivery of safe and reliable electric service to NIPSCO's customers, as allowed by the TDSIC Statute. NIPSCO performed a rigorous analysis of its current electric system as well as anticipated future system needs and does not expect the Plan to change significantly. With that said, it is certainly possible that projects in the Plan might change or be replaced, or that new projects might be proposed. This depends on a number of factors, including, but not limited to: (1) the continued evolution of the TDSIC Risk Model; (2) identification through routine and special inspection and assessment cycles of assets at risk for continued operability; (3) identification of risks through other NIPSCO process improvement and safety initiatives; (4) load growth and potential economic development projects; (5) the development of new technology to increase public safety or that offer more economical solution; and (6) the development of unpredicted asset failure, of which more expedient replacement or repair is required.

<u>FLEXIBLE INVESTMENT PLAN</u>

Q24. How will NIPSCO update the 2021-2026 Electric Plan if a project in the Plan is proposed to be replaced or if a new project is proposed to be added to the Plan?

A24. Any project in the Plan that is proposed to be replaced or any new project that is proposed to be added to the Plan would be included in a plan update filing pursuant to Section 9(b) of the TDSIC Statute. If approved, NIPSCO would then seek deferral of costs associated with the replaced or new project and recovery of the costs associated with a replaced or new project in future plan update filings, based on the reasons discussed immediately above.

Q25. Please describe the incremental benefit associated with the 2021-2026 Electric Plan.

A25. The 2021-2026 Electric Plan focuses on maintaining safe, reliable service for NIPSCO's customers, while incorporating system upgrades. The Plan addresses eligible investments of safety, reliability, and grid modernization included in the TDSIC Statute. The Plan's investments positively impact electric reliability, safety, and grid modernization while resulting in positive economic impact for Indiana. The Plan also provides for appropriate economic development projects in the future, although none are proposed at this time. Reliability drivers include the following:

- Reducing direct customer outages;
- Shortening customer outage durations;
- Maintaining continuity of service (self-healing system);
- Better managing peak system loading periods;
- Increasing flexibility for system sourcing;
- Increasing system visibility and validation;
- Enabling future technologies; and
- More timely notification of outages (AMI).

Safety is of utmost importance to NIPSCO, its customers, and the broader public. Maintaining safety performance is a requirement for NIPSCO's workforce and its customers, and thus one of the main objectives of the Plan. The continued safety of NIPSCO's employees and customers is enhanced when the likelihood of violent failures (i.e., explosions, fires, downed power lines) are mitigated through aging infrastructure replacement. The increased visibility for fault detection and system modernization assists in preventing violent failures from occurring as well.

Lastly, the extension of new facilities provides for a more robust system to meet deliverability or interconnection requirements.

As discussed in detail above, NIPSCO has a large number of aging assets on its electric transmission and distribution system. The assets have aged naturally as a function of NIPSCO's service territory development during the rapid build out in the 1960s and 1970s, and many assets have met or are approaching their end of life. The proactive replacement of aging infrastructure will help maintain the reliability of NIPSCO's electric transmission and distribution systems, which are growing older, and therefore riskier, with each passing year. The 2021-2026 Electric Plan targets the highest risk and consequence of failure assets. In developing the Plan, NIPSCO carefully prioritized the list of planned investments to optimize the benefits of the investments while taking into account execution resources, engineering resources, and system constraints. For risk-based projects, the Plan represents an optimized risk reduction of approximately 16% versus a break/fix strategy.

The proactive replacement of aging infrastructure also provides opportunities to replace old equipment with modern technology in a systematic and deliberate manner. While costs are primarily delineated by the four asset class categories and project types (T&D Substation and T&D Line), NIPSCO proactively evaluated the execution of projects throughout the Plan and combined projects or project categories for efficiency. This "combination" allows original project categories to be consolidated into singular projects to effectively gain time and reduce overall capital costs. For example, the original driver for a transformer replacement project may be age and condition; however, the new transformer will include substation automation and communication components that are primarily driven by grid modernization. Through this consolidation process, NIPSCO can reduce mobilization, overhead, and labor costs, and potentially reduce the number of scheduled outages.

Grid modernization benefits include optimizing NIPSCO's outage response, reducing unplanned asset failures, improving system flexibility, and laying a groundwork for future growth to implement modern technologies. By proactively enhancing the monitoring of asset and system health, NIPSCO will be able to avoid increasing levels of reactive or emergency work, which are often more expensive to perform due to premium labor rates and expediting fees, and often introduce additional, preventable safety risks. Unplanned asset failures are also typically more disruptive to customer service and have the potential to damage customer equipment or jeopardize personnel safety. Grid modernization projects include modern system protection devices that provide for faster clearing of system faults which will protect the health of NIPSCO's assets and minimize the breadth of future outages.

Finally, the 2021-2026 Electric Plan fosters economic development, a key benefit of the Plan that will be spurred by these investments in the electric system. As Witness Becker discusses more fully, the Economic Impact Report prepared by Sargent & Lundy shows the positive economic impact of these investments to Northern Indiana. The Plan also provides for appropriate economic development projects in the future, although none are proposed at this time. Additionally, to the extent a future economic development investment is identified, NIPSCO would present the proposed project in a plan update filing pursuant to Section 9(b) of the TDSIC Statute.

Q26. How has NIPSCO approached the quantification of incremental benefits associated with the 2021-2026 Electric Plan?

A26. NIPSCO expects to see an aggregate reduction in the risk of major asset failure associated with the transmission and distribution projects in the

Plan of approximately 16%, and each project included in the Plan has been chosen and designed with the intent to reduce the likelihood of failure and the attendant risk to service reliability and continuity and the availability of system capacity. The benefit to NIPSCO's customers from Aging Infrastructure and System Deliverability investments cannot be easily calculated in an actuarial calculation. While it would be convenient if the benefit of each of the Aging Infrastructure and System Deliverability projects could be quantified in monetary terms to permit some kind of a cost-benefit analysis, the value to be placed on life and property potentially at risk from the failure of one of these assets is too high to realistically contemplate. However, investments in Grid Modernization is one area where the estimated benefits can be monetized. The Distribution Automation Program Business Case (Confidential Attachment 2-E) monetizes the value of the proposed distributed automation program. NIPSCO and Leidos utilized the U.S. Department of Energy's Interruption Cost Estimation (ICE) calculator to place a value on customer interruption costs and savings that would be realized by customers as a result of NIPSCO implementing specific Grid Modernization investments.[9] The

[9] Witness Kiergan also discusses a cost-benefit analysis conducted for the AMI Project.

report summarizes that investments in DA grid modernization result in a cost savings of approximately $592 million over the period of twenty years, compared against the investment of approximately $52 million for DA grid modernization projects over a 10-year period. The total NIPSCO DA plan will not be completed within the 2021-2026 Electric Plan window.

Q27. Are the estimated costs of the eligible improvements included in the 2021-2026 Electric Plan justified by incremental benefits attributable to the Plan, as required under Section 10(b)(3) of the TDSIC Statute?[10]

A27. Yes. The estimated costs of the eligible improvements included in the 2021-2026 Electric Plan are justified by the incremental benefits. Some of the benefits identified above are readily quantifiable, and others are more qualitative in nature. The Plan contains solutions that will enhance customer and employee safety, avoid outages, preserve operational and planning contingencies, provide superior equipment protection, and meet evolving customer demands. By virtue of achieving all of these benefits in a thoughtful, planned and cost-efficient manner, the Plan provides

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[10] Section 10(b)(3) of the TDSIC Statute requires a finding that the estimated costs of the eligible improvements (i.e., projects and programs) included in a proposed TDSIC plan be justified by the incremental benefits attributable to the plan.

incremental benefit for NIPSCO's customers that outweigh the estimated costs.[11]

Q28. How has NIPSCO incorporated process improvements and lessons learned from its previous TDSIC filings?

A28. Over the past few years, NIPSCO has been able to make significant improvements in the development of its TDSIC capital investment plan. Historically, NIPSCO forecasted capital planning in a logical and planned manner, but this was not based on the same level of project selection criteria and project level detail as its TDISC plan has been. Based on feedback received and internal learning through the plan development process, NIPSCO has been able to make considerable improvement providing a much greater level of detail utilizing risk modeling, condition-based assessment, system constraints, resource constraints, and long-range system planning to better define projects that are necessary and included in the Plan. Improvements have also occurred in developing more accurate project estimates, including extending Class 3 estimates out to 18 to 24 months. Project management and construction has also been able to build

[11] Estimated costs for the 2021-2026 Electric Plan are discussed separately below.

on the experience over the past several years, becoming more experienced in project planning and execution.

<u>PLAN UPDATE PROCESS</u>

Q29. Will the 2021-2026 Electric Plan need to be updated?

A29. Yes. Section 9(b) of the TDSIC Statute states that "[t]he public utility shall update the public utility's TDSIC plan under subsection (a)(2) at least annually." Consistent with this provision, NIPSCO proposes to update the 2021-2026 Electric Plan annually, but in no event more frequently than once every six months.[12] In addition to the statutory requirement to file an updated plan, it is prudent and necessary for NIPSCO to systematically and periodically review, revise, and update its Plan to respond to the dynamic nature of its transmission and distribution system, customer demand, and equipment failures. While considerable analysis and thought went into the development of the 2021-2026 Electric Plan, it is important to note that the Plan is reflective of the characteristics of the electric system and the needs of NIPSCO's customers as they exist at the time the Plan was developed. As NIPSCO learns more in the upcoming years, the Plan will be updated as

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[12] As provided in Section 9(f) of the TDSIC Statute, NIPSCO will not file a petition under Section 9 more frequently than once every 6 months.

necessary. Through normal operations, information is continually gathered around asset condition data. This information will be integrated into the TDSIC Risk Model and will serve to modify the probability of asset failure. Additionally, configuration of the system, connectivity of critical customers, and other system events will serve to modify the consequence of failure driver in the TDSIC Risk Model. As customer demands evolve, both from a location and utilization perspective, system deliverability requirements must evolve.

Lastly, the 2021-2026 Electric Plan seeks to address risk by proactively replacing the riskiest elements in NIPSCO's system. Some elements of the system are best utilized in a "run to failure" mode, while other elements may fail before their planned replacement cycle arrives. While the models utilized to develop the Plan are sound, it is impossible to perfectly predict the future. As such, when these unanticipated events occur, the Plan will be re-prioritized. As such, a prudent 6-year plan must be dynamic. As information inputs change, the Plan will continue to be optimized to ensure the best plan possible is being deployed, and, when necessary, NIPSCO will work with all stakeholders when seeking to add new projects to the Plan.

Q30. Please describe the Plan update process proposed in this filing.

A30. NIPSCO's proposed update process is similar to the process used for Electric Plan 1 with the exception that NIPSCO is proposing to update its Plan annually. NIPSCO proposes to continue the current process of meeting with its stakeholders approximately four weeks prior to filing each Plan update.

In its Fall filing, the Plan will be updated with NIPSCO's best estimate by project for each calendar year. The risk registers (Confidential Appendices A and B) will be updated as new, relevant information becomes available during the Plan update process. Project Change Request ("PCR") forms and testimonial explanations will be provided to support project estimate changes greater than $100,000 and greater than 20% during the current year for projects. Actual costs (direct capital, indirect capital, and allowance for funds used during construction ("AFUDC")) will be included in the annual Plan update after a given calendar year is closed out. The annual Plan update will define the detailed project scopes and update unit cost estimates for the next calendar year, if needed.

COST ESTIMATES AND ESTIMATE DEVELOPMENT

Q31. Please summarize the estimated costs associated with the 2021-2026 Electric Plan.

A31. As shown in Confidential Attachment 2-A, the total estimated capital cost of the 2021-2026 Electric Plan is $1,625,520,697, including direct capital of $1,396,615,415, indirect capital of $181,560,012, and AFUDC of $47,345,270. As explained by Witness Meece, indirect capital costs are incurred in performing capital projects but are not charged directly to a specific work order. As shown in Confidential Attachment 2-A, the total estimated O&M cost of the 2021-2026 Electric Plan is $10,014,705. Table 2 shows the estimated costs associated with the 2021-2026 Electric Plan, by project year.

Table 2 – Annual Cost Breakdown by Type

	Year 1 2021	Year 2 2022	Year 3 2023	Year 4 2024	Year 5 2025	Year 6 2026	Total
Direct	$105,324,448	$222,556,740	$229,233,442	$275,229,152	$276,892,422	$287,379,211	$1,396,615,415
Indirect	$13,692,179	$28,932,376	$29,800,350	$35,779,789	$35,996,017	$37,359,301	$181,560,012
AFUDC	$3,570,498	$7,544,672	$7,771,017	$9,330,269	$9,386,653	$9,742,161	$47,345,270
Total Capital	$122,587,125	$259,033,788	$266,804,809	$320,339,210	$322,275,092	$334,480,673	$1,625,520,697
Total O&M	$83,418	$2,329,335	$2,263,358	$2,301,811	$1,680,577	$1,356,206	$10,014,705

Q32. Does the total estimated capital cost of the 2021-2026 Electric Plan include plan development costs and preliminary survey and investigation ("PS&I") costs?

A32. Yes. Both types of costs have been included in the Plan, but are included in the project costs in different ways. As has been NIPSCO's standard practice, PS&I costs for specific projects will be included in the project's land acquisition, preconstruction, environmental, and construction work order (direct capital) and typically will be distributed when the work order is opened based upon the type of typical project planning and sequencing year of project execution. Additionally, approximately $3 million of plan development costs will be amortized over the life of the Plan as capital overhead (or indirect capital).

Q33. Please describe the different techniques used by NIPSCO and S&L to develop a cost estimate for a project.

A33. A cost estimate is developed at a point in time, and is based on the information known when the estimate is developed. As the project progresses, the information used as inputs into the cost estimation process becomes more accurate. There are different techniques used by NIPSCO to develop a cost estimate for a project. NIPSCO utilizes the following standard AACE International ("AACE") class estimate definitions:

- Analogous Class 5 (the estimate is based on expert judgment and overall system factors) – these estimates have very little of the total project defined (0 – 2%) and require very little engineering in order to estimate.
- Parametric Class 4 (the estimate is developed using application of similar type estimates and specific equipment factors) – these estimates are done at about 1 – 15% of the total project being defined

and usually have an engineering or feasibility study associated with them.

- Semi-detailed Class 2 / 3 (the estimate is developed with unit costs and with assembly level line items) – these estimates are performed at 10 – 70% project definition, have detailed engineering nearly complete, and use bids tendered as development for the estimate.
- Detailed Class 1 (the estimate is developed with unit costs and with detailed bill of materials) – these estimates are performed at 50 – 100% project definition with the detailed engineering complete, bids tendered and verified to develop the estimate.

Table 3 shows the AACE level of estimate for each project or program type at the time of filing. As plan years proceed the level of estimate will continue to progress. Projects three years from execution will have gone through, or are going through the scoping phase of the project and may progress to a Class 4. Projects will have updated estimates at an AACE Class 3 level 18 to 24 months from execution. Programs will have been detailed engineered by the execution year 1 and can be considered a Class 4.

Table 3 – Estimate Classes

Class Estimate Table						
Project Type	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**
New or Replace Transformer	Class 3	Class 3	Class 5	Class 5	Class 5	Class 5
New or Replace Breaker	Class 3	Class 3	Class 5	Class 5	Class 5	Class 5
Upgrade Relay	Class 3	Class 3	Class 5	Class 5	Class 5	Class 5
New or Replace Communication Equipment	Class 3	Class 3	Class 5	Class 5	Class 5	Class 5
New or Upgrade Substation Automation	Class 4	Class 5	Class 5	Class 5	Class 5	Class 5
Replace Potential Transformer	Class 4	Class 5	Class 5	Class 5	Class 5	Class 5
Replace Disconnects/Substation Switch	Class 4	Class 5	Class 5	Class 5	Class 5	Class 5
New or Rebuild Circuit	Class 3	Class 3	Class 5	Class 5	Class 5	Class 5
New or Replace Fiber Optic Line	Class 3	Class 3	Class 5	Class 5	Class 5	Class 5
Replace Line Switch	Class 4	Class 5	Class 5	Class 5	Class 5	Class 5
Life Extenstion Steel Structure	Class 4	Class 5	Class 5	Class 5	Class 5	Class 5
Replace Underground Cable	Class 4	Class 5	Class 5	Class 5	Class 5	Class 5
Life Extension Wood Pole	Class 4	Class 5	Class 5	Class 5	Class 5	Class 5
New or Upgrade Disbribution Line Automation	Class 4	Class 5	Class 5	Class 5	Class 5	Class 5
Upgrade Advanced Metering Infrastructure	Class 4	Class 5	Class 5	Class 5	Class 5	Class 5

Q34. Please describe the cost estimates that are provided as part of the 2021-2026 Electric Plan.

A34. The 2021-2026 Electric Plan (Confidential Attachment 2-A) provides a summary of project level estimates by year, which includes all investments represented in direct dollars. Confidential Attachment 2-A, Confidential Appendix C includes the detailed cost estimates for the 2021 projects. Confidential Attachment 2-A, Confidential Appendix D includes the detailed cost estimates for the 2022 projects. Confidential Attachment 2-C includes design basis cost estimates broken down by direct and indirect costs (including labor and material) for Program Projects for 2021 and 2022, and for all projects included in 2023-2026. The cycle that NIPSCO projects are refined include initial scoping and estimating efforts three years in advance of execution, detailed engineering two years in advance of execution, and resource planning one to two years in advance of execution. Other costs included in the years leading up to execution include land purchases, environmental studies, and other preconstruction activities.

Q35. How did NIPSCO develop the direct capital cost estimates for the Site Specific Projects?

A35. The direct capital cost estimates for 2021 and 2022 were developed by

NIPSCO's Project Scope and Estimate Development Team utilizing detailed site reviews, internal engineering, operations, and planning expertise and outside engineering input. All estimates were reviewed by NIPSCO's internal stakeholders. The project estimates for 2021 and 2022 are considered Class 3/4 estimates. The direct capital cost estimates for 2023-2026 were developed by S&L and NIPSCO using a modular cost estimating approach using historical unit cost data, labor rates for external contractors, labor rates for internal NIPSCO labor, vendor budgetary quotations for major substation assets, NIPSCO's Geographic Information System ("GIS") for evaluating line rebuild assets, and construction contractor per unit budgetary validations for installation. The modular estimates were then applied to each project based on type of known scope. These project estimates are considered Class 5. However, given the repetitive nature and the large number of projects, along with NIPSCO's experience with this type of work, there is a high level of confidence in these cost estimates. The estimate review process is continuous throughout the project development process.

Q36. How did NIPSCO develop the direct capital cost estimates for the Program Projects?

A36. The direct capital cost estimates for 2021-2026 were developed by S&L and NIPSCO internal stakeholders using historical unit cost data, vendor quotations for typical equipment utilized for the project application, and knowledge of executing projects within NIPSCO's service territory.

Q37. How did NIPSCO develop the estimated indirect capital costs?

A37. NIPSCO used historical data from its Electric Plan 1 update filings to develop the estimated indirect percentage. The resulting percentage was then applied to the direct capital cost for each year of the Plan to arrive at the total indirect cost estimate. NIPSCO used 13.0% for indirect capital costs in the Plan.

Q38. How did NIPSCO develop the estimated AFUDC rate?

A38. NIPSCO used historical data from its Electric Plan 1 update filings to develop an estimated AFUDC rate. The resulting rate was then applied to the sum of the direct capital cost and indirect capital cost for each year of the Plan to arrive at the total AFUDC cost estimate. NIPSCO used 3.0% for AFUDC in the Plan.

Q39. Do indirect capital costs and AFUDC fluctuate over time and how have they been incorporated into the project cost estimates?

A39. Yes. Witness Meece discusses the origin and calculation of indirect capital costs and AFUDC. Indirect capital costs fluctuate based on a variety of inputs, including the level of direct capital costs and indirect labor and benefit costs. The actual indirect capital and AFUDC costs will be included in the Plan update when a given calendar year is closed out.

Q40. How does the 2021-2026 Electric Plan provide the best estimate of the cost of the transmission and distribution system investments included in the Plan?

A40. The 2021-2026 Electric Plan includes projects that are similar to work NIPSCO performed in Electric Plan 1. NIPSCO utilized S&L to complete the modular cost estimates, followed by internal stakeholder reviews of those estimates. NIPSCO has gained and continues to gain experience with respect to the costs necessary for project completion, and cost estimates for this work reflected from NIPSCO's experience on the range of executed projects of the previous Electric Plan 1 projects of different types.

S&L took a more in depth look at five large substation projects in the 2021-2026 Electric Plan. Walkdowns were performed, site boundary survey's produced, a preliminary work scope identified, with conceptual layouts prepared for project execution, route reviews, and NIPSCO internal stakeholder reviews performed. The estimates prepared for these five large substations were based on a bottom up, non-modular estimating approach. Cost data from recent projects and updated budgetary quotations from construction contractors were used as the basis for the estimates in most cases, with experience modifiers considered for site specific conditions. For example, areas where extensive dewatering would be required were identified. A detailed bill of materials was developed through the preliminary engineering phase and updated prices were obtained from NIPSCO suppliers.[13] A preliminary, high level schedule was also developed to identify detailed engineering, land acquisition, and permitting lead time requirements.

Smaller project estimates, typically under $1,000,000, are generally based on parametric or unit price estimates that reflect a mix of contractor and internal labor resources similar to the allocation of work maintained during Electric Plan 1. A review of route and site conditions was completed for many projects.

For all projects, broad internal stakeholder input was collected to assure

[13] "Bill of materials" is an industry term used to describe a list of the materials or equipment required for the completion of a specific project.

comprehensive integrated work scopes were documented and validated through a formal review process. NIPSCO followed a rigorous project development, cost estimating, and review process to provide its best estimate for each project included in the Plan. Further detail about the estimation process for each project is included in the individual project descriptions found below.

The 2021 Class 3 project estimates were scoped and resource-planned by NIPSCO. The 2022 projects were also scoped and resource-planned by NIPSCO. Estimates were prepared utilizing budgetary quotes from equipment suppliers for typical major equipment; review of NIPSCO's historical data for support costs like environmental, engineering, and construction management; and current labor rates for external resources. Estimates were then produced utilizing a modular approach to estimating. S&L substantiated the 2023-2026 project estimates by evaluating them against projects executed within the 2018-2019 year and against the 2021-2022 NIPSCO detailed cost estimates. The estimates produced by S&L were found to be well within the order of magnitude expected for a Class 5 estimate. In addition, S&L conducted site visits utilizing design basis checklists to assess criteria such as the potential land constraints for projects where site expansion is expected for project execution.

Based on the estimates produced by S&L and NIPSCO, and the comparison to actual costs of similar projects in recent years, NIPSCO is confident that these are the best estimates for the respective stages of planning for the projects included in the 2021-2026 Electric Plan. The Plan includes two types of projects: (a) Program Projects and (b) Site Specific Projects (substation or line projects). NIPSCO has provided estimates for the two types of projects:

- **Program Projects** include Class 5 estimates for years 2022-2026. Design Basis Documents were created for the generic Scope of Work associated with the program and a cost estimate was produced based on the Scope of Work. The program projects are executed based upon execution sequencing, criticality and potential for improved customer satisfaction. Class 4 estimates are provided after detailed engineering is completed.

- **Site Specific Projects** include Class 3 to Class 5 estimates. The Site Specific Projects are projects which were estimated using a "bottom up" modular cost estimating approach, based upon known scope at the time of the estimate. Estimate modules created for these projects were created using historical unit pricing, vendor equipment quotations based on average equipment executed for the type of application, published contractor rates, and current knowledge of assumed project execution. It is appropriate to estimate in this manner due to the volume of individual projects contained within the Plan and the year at which execution will begin.

In summary, NIPSCO worked with S&L to develop the best estimate of the cost for each investment. Therefore, the estimates included are NIPSCO's best estimates as of the time of filing. NIPSCO will continue to refine these estimates as it enters into different phases of the project cycle and provide the refined estimates in future plan updates.

CONTINGENCY AS A COMPONENT OF ESTIMATION

Q41. Is inclusion of contingency consistent with the Commission's findings relating to the "best estimate" of costs under the TDSIC Statute?

A41. Yes. When determining whether a company has presented the best estimate of project costs under the TDSIC Statute, my understanding is the Commission has repeatedly found that inclusion of contingency is necessary in order to be considered the "best estimate" of project costs. For example, in Cause No. 45330 related to a NIPSCO Gas TDSIC Plan, in response to challenges about the inclusion of contingency as part of project cost estimates from certain parties, the Commission found that "the exclusion of contingency in the cost estimate would be unreasonable and would not establish the best cost estimate as required by the TDSIC

Statute."[14] Similarly, in another 2020 order, the Commission stated: "we find the exclusion of contingency from the cost estimate would be unreasonable and would not establish the best cost estimate as required by the TDSIC Statute."[15]

Q42. Did NIPSCO include contingency in its project cost estimates?

A42. Yes. Consistent with the Commission's findings that best cost estimates must include a level of contingency, NIPSCO included contingency consistent with the AACE Recommended Practice for cost estimate classification.[16] The contingency incorporated in the estimates for each of the 2021-2026 Electric Plan projects is consistent with industry practice for these types of projects and is consistent with the AACE Recommended Practice and NIPSCO's experience for risk that can impact a project cost gained through the execution of projects within Electric Plan 1.

The AACE Recommended Practice is based on project maturity or progress of project engineering or project development. The preliminary

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[14] Commission order in Cause No. 45330 at p. 23, issued July 22, 2020. In this order, the Commission also found that "the level of contingency reflected in [NIPSCO's] cost estimates is reasonable." *Id*.

[15] Commission order in Cause No. 45264 at pp. 22-23, issued March 4, 2020.

[16] The AACE is an organization with over 7,000 members in 100 countries and focuses on cost engineering, estimating and cost management.

engineering for most projects in the 2021-2026 Electric Plan would support a Class 5 estimate based on the application of recent construction experience, added efforts to inspect and understand site conditions, identification of real estate and environmental requirements, and characterization of project risks, especially on the larger transmission projects. A contingency amount, by project, can be found in the project estimate summaries included in Confidential Attachment 2-A, Confidential Appendix C for 2021, and Confidential Attachment 2-A, Confidential Appendix D for 2022. Confidential Attachment 2-C shows the contingency amount for each of the projects included in the 2021-2026 Electric Plan. As shown in Confidential Attachment 2-C, the total contingency is approximately 10% of the direct labor component of the estimates for all projects.

Attachment 2-H includes additional information supporting NIPSCO's inclusion of contingency in its project cost estimates, including (1) use of contingency for purposes of cost estimation, (2) inclusion of contingency improves cost estimates, and (3) why contingency is used in the estimating process.[17]

Q43. Please explain the process used by NIPSCO to determine the appropriate contingency for each project.

A43. NIPSCO utilizes a process of progressive elaboration to develop project details and identify risk for the project. Once this is complete, an appropriate contingency for a project is assigned. As the project is developed further through an iterative process, the process is repeated. Many of the large projects within the 2021-2026 Electric Plan had several formal review meetings with a wide variety of internal stakeholders to validate the project details and relevant risks (including potential risks). The AACE Recommended Practices are based on the maturity of the project design or engineering. NIPSCO's process is intended to identify the potential issues or risks. Where there is a high probability that a risk will be realized and a mitigation plan can be defined with a cost estimate, NIPSCO defines the solution and includes the costs in the estimate. Where

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[17] As shown in <u>Confidential Attachment 2-C</u>, <u>Confidential Attachment 2-A</u>, Confidential Appendix C (2021), and <u>Confidential Attachment 2-A</u>, Confidential Appendix D (2022), the 3% annual escalation factor is only applied to base cost capital estimates, but not to contingency amounts.

this is not possible, the Company adds the issue to the risk register and applies the contingency if the risk is realized.

Q44. Has NIPSCO evaluated the risks considered in establishing the contingency for each project?

A44. Yes. The potential risks associated with the project types are identified within the 2021-2026 TDSIC Investment Plan Cost Analysis developed by S&L (Confidential Attachment 2-C).

Q45. Are these the same risks that NIPSCO considered in determining which projects to include in the 2021-2026 Electric Plan?

A45. No. The risks referenced in the contingency questions above describe risks related to the *implementation* of specific projects. The TDSIC Risk Model used in determining which projects to *include* in 2021-2026 Electric Plan, evaluate the risk to the system associated with safety, reliability, and deliverability and selected the projects most likely to benefit the NIPSCO system and its customers.

AGING INFRASTRUCTURE INVESTMENTS

Q46. Please describe the significance of replacing aging infrastructure.

A46. Aging infrastructure is a common issue faced by utilities. The electric system is characterized by technology developed in the 1950s or earlier. Much of the infrastructure was constructed in the 1960s and 1970s during a rapid buildout of the electric grid using the best technology available at the time. Many of these assets have now exceeded the projected life expectance by many years and have a failure rate that continues to increase. As this large asset base continues to age it produces a higher concentration of projects similar to the original buildout that must be replaced to maintain the increasing level of system reliability expected by the today's customers. As these assets are replaced, new technology is also introduced improving system performance by replacing the obsolete technologies currently in service. The additional benefits achieved include improved system performance impacting safety, reliability, and operational performance, as well as system hardening and resiliency.

Q47. Please summarize the Aging Infrastructure investments included in the 2021-2026 Electric Plan.

A47. Aging Infrastructure investments are projects aimed at reducing reliability risk by replacing or rehabilitating electric transmission and distribution assets that are of high consequence and are either approaching, have met, or have surpassed their expected life. Aging Infrastructure investments were identified in two ways. First, NIPSCO worked with the asset management team at S&L to update an overall risk model for its power transformers, circuit breakers, and circuits. This is the same risk model used in Electric Plan 1. This was used to develop the proposed 2021-2026 Electric Plan (the results of the TDSIC Risk Model are included in the Long-Term Investment Plan (<u>Confidential Attachment 2-B</u>, Confidential Appendix A)). The result of this work includes the reports identified above as well as the Asset Register for Risk Based Projects included in the Plan as <u>Confidential Attachment 2-A</u>, Confidential Appendix A. An optimized portfolio of electric transmission and distribution assets was then selected to be addressed based on the result of this risk analysis. These major electric transmission and distribution assets are critical, highly-engineered components requiring significant lead time prior to execution. This process included assigning a consequence of failure ("COF") and likelihood of failure ("LOF") to each of the assets.

Second, NIPSCO independently evaluated groups of system assets to identify and prioritize the assets within each group with the greatest potential of failure based on their age and condition. Rather than using a complex risk model for these more numerous assets, NIPSCO analyzed its routine testing and maintenance records to identify the individual assets within each group that were most in need of replacement and used the results of that analysis to create asset registers for the following groups:

Deliverability and Condition Based Projects
Arrester Projects - Transmission
Battery & Charger Equipment Projects - Transmission
Potential Transformer Projects - Transmission
Substation Switch Projects - Transmission
LTC Control Upgrade Projects - Transmission
Annunciator Projects - Transmission
Line Switch Projects - Transmission
Substation Switch Projects - Distribution
Arrester Projects - Distribution
Battery & Charger Equipment Projects - Distribution
Substation Feeder Cable Projects - Distribution
Potential Transformer Projects - Distribution
Power Transformer Projects - Distribution
Switches to Clear Incoming Lines Projects - Distribution
Line Switch Projects - Distribution
LTC Control Upgrade - Regulator Projects
Fiber Optic Cable - Transmission
Upgrade 138kV Circuit Protection Breakers & Relays
Upgrade 69kV Circuit Protection Breakers & Relays
Upgrade 34kV Circuit Protection Relays
Underground Cable Replacement

*2021 is Base year for Deliverability groups

S&L reviewed these asset groups and completed design basis statements of work as provided in Confidential Attachment 2-C. The asset registers for the Deliverability and Condition Based Projects are included in the Asset Register for Risk Based Projects (Confidential Attachment 2-A, Confidential Appendix B).

Q48. Are there any projects not included in the asset registers?

A48. Yes. Based on the nature of how specific projects are selected, the Circuit Performance Improvement, Steel Structure Life Extension, and Pole Replacement projects are not included in an asset register.

Q49. Please summarize how the Circuit Performance Improvement investments were or will be selected for inclusion in the 2021-2026 Electric Plan.

A49. Circuit Performance Improvement investments are determined on an annual basis by analyzing reliability data and determining which circuits are most in need of improvement. For purposes of development of the Plan, expected projects are included in categories such as sectionalization, distribution automation, circuit rebuild, conductor replacement or other specified performance improvement based on root cause. The methodology NIPSCO utilizes to identify these needs and the appropriate solutions are detailed below. NIPSCO performs a structured assessment of its circuits systems on an on-going basis to identify and schedule needed investments well in advance of execution to proactively address circuits with the poorest reliability. The Circuit Performance Improvement investments included in the 2021-2026 Electric Plan therefore differ from the other projects included in the Plan because the needed investments are identified based on the evaluation of reliability and condition. At the beginning of 2021, NIPSCO reviewed 2020 performance and determined the 2021 Circuit Performance Improvement projects and developed project scope and cost estimates. The estimates for 2021 are included in the Plan, and estimates for future years will be updated in NIPSCO's plan update filings.

Q50. Please summarize how the Steel Structure Life Extension investments were or will be selected for inclusion in the 2021-2026 Electric Plan.

A50. The Steel Structure Life Extension project is designed to extend the life of NIPSCO's steel structures or rehabilitate those that do not meet the accepted strength requirements. This project is necessary to address NIPSCO's aging steel structure population that is continuing to deteriorate. Over the life of the Plan, NIPSCO will inspect approximately 1,779 structures, and based on historical experience expects approximately 20% of those assets inspected to require some type of rehabilitation. Based on inspection, estimates will be updated in NIPSCO's plan update filings, and each structure will have the appropriate life-extending improvements made. This project will increase transmission system reliability through system hardening and resiliency.

Q51. Please summarize how the Pole Replacement investments were or will be selected for inclusion in the 2021-2026 Electric Plan.

A51. The Pole Replacement project is designed to inspect, treat, and replace NIPSCO's wood pole population. Wood poles are the largest asset classification on NIPSCO's transmission and distribution system. With the average age wood poles being greater than 40 years, it is necessary to actively assess the condition and make any necessary repairs or replacements to ensure integrity of the system. This is accomplished by development of a 10-year rolling inspection of each pole to determine condition and to replace or treat the pole for life extension if necessary. The inspection is based on industry standard methodology to determine remaining life. With each inspection, the pole will either be treated to reduce the rate of future decay, or, if it does not pass the test, the pole will be replaced. The pole inspection, treatment, and replacement project improves system reliability, safety, and system hardening during major event days by ensuring all poles meet the strength requirements set forth in the National Electric Safety Code ("NESC"). NIPSCO plans to inspect approximately 184,000 poles over the life of the Plan. Based on historical experience, it is anticipated that approximately 5-6% of the inspected poles will be replaced, with the exception of those already inspected in years with above-average rejection rates. Based on inspections, estimates will be updated in NIPSCO's plan update filings to account for variances to historical approximations.

AGING INFRASTRUCTURE PROJECTS

Q52. Please describe the Aging Infrastructure projects included in the 2021-2026 Electric Plan.

A52. Table 4 shows the Aging Infrastructure projects included in the 2021-2026 Electric Plan.

Table 4 – Aging Infrastructure Projects

Transmission	
Project ID	**Project Name**
TSA1	Arrester Projects
TSB1	Battery & Charger Equipment Projects
TSPT1	Potential Transformer Projects
TSSW1	Substation Switch Projects
TSRUX	Relay Upgrade Projects
TSBRUX	Breaker and Relay Upgrade Projects
TSTUX	Transformer Upgrade Projects

TSNRSX	New/Rebuild Substation Projects
TLSW1	Line Switch Projects
TLST1	Steel Structure Life Extension Projects
TLNRLX	Circuit Rebuild Projects

Distribution	
Project ID	**Project Name**
DUG1	Underground Cable Replacement Projects
DSA1	Arrester Projects
DSB1	Battery & Charger Equipment Projects
DSSW1	Substation Switch Projects
DSFC1	Substation Feeder Cable Projects
DSTU1	Power Transformer Projects
DSBRUX	Breaker and Relay Upgrade Projects
DSTUX	Transformer Upgrade Projects
DSNRSX	New/Rebuild Substation Projects
DLCP1	Circuit Performance Improvement (CPI) Projects
DLWP1	Pole Replacement Projects
DLSW1	Switches to Clear Incoming Lines Projects
DLSW2	Line Switch Projects
DLLED1	LED Street Lighting
DLNRLX	Circuit Rebuild Projects

Aging infrastructure is a significant portion of the Plan, and the projects have been separated into three categories: (1) risk ranked projects, (2) projects ranked using other data sources, and (3) assets included in the TDSIC Risk Model (<u>Confidential Attachment 2-B</u>, Confidential Appendix A), but selected and prioritized based on independent assessments.

- <u>Risk Ranked Projects</u>. Overhead and underground circuit rebuild projects, transformers, and circuit breaker assets are identified and prioritized on the Asset Register for Risk Based Projects (<u>Confidential Attachment 2-A</u>, Confidential Appendix A). These are major transmission and distribution projects requiring significant lead time and planning to execute.

- Projects Ranked Using Other Sources. This includes Aging Infrastructure assets that were selected and prioritized based on the Asset Register for Non-Risk Based Projects (Confidential Attachment 2-A, Confidential Appendix B). These are projects that were ranked using other factors such as age, condition, and capacity. For example, Distribution Batteries are included for replacement based upon field testing performed on an annual basis to determine which batteries are most in need of replacement.

- Projects Ranked Using Independent Assessments. Projects in this category include oil circuit breakers, wood poles, steel tower rehabilitation, underground cable, circuit performance, and system deliverability and, except as noted above, are included in the Asset Register for Non-Risk Based Projects (Confidential Attachment 2-A, Confidential Appendix B).[18]

The Underground Cable Replacement project focuses on the replacement of aged underground cable, and focuses on the non-jacketed type. Underground cable became more mainstream as technology developed during the 1970s and into the 1980s. This early design was a non-jacketed cable with early generation dielectric composition. NIPSCO is currently experiencing an increasing rate of failure of this early generation cable, which results in increased outages, which can be of a long duration due the repair process. Much of the cable requires direct replacement due to the non-jacketed design, while some of the 1980s cable that does have a jacket can be treated for life extension based on a condition assessment. The Underground Cable Replacement project includes a detail list of all cable planned for inspection followed by replacement during the life of the Plan. Replacement of this vintage of cable will improve system reliability by replacing obsolete

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[18] The Circuit Performance Improvement, Steel Structure Life Extension, and Pole Replacement projects are all ranked using independent assessments, but they are not listed in the Asset Register for Non-Risk Based Projects (Confidential Attachment 2-A, Confidential Appendix B). Each of these projects has been described in detail above.

technology with new cable designs expected to last more than 40 years.

NIPSCO's Aging Infrastructure investments include replacements from all categories within the TDSIC Risk Model (<u>Confidential Attachment 2-B</u>, Confidential Appendix A) including: transformers, breakers, and overhead and underground circuit rebuilds. Another category included in the Plan is system protection modernization efforts such as breaker relay upgrades and fiber optic lines. The Plan includes not only replacing aged assets, but the extension of the useful life of assets. The Plan also addresses assets such as arresters, batteries, switches, annunciators, and potential transformers.

Q53. Please describe the TDSIC Risk Model (<u>Confidential Attachment 2-B</u>, Confidential Appendix A) used to rank and help select the risk ranked Aging Infrastructure projects included in the 2021-2026 Electric Plan.

A53. When considering the proactive replacement of some of the aging infrastructure assets, NIPSCO used a systematic risk model to quantify the criticality of three types of major transmission and distribution assets to the overall electric system: (1) overhead and underground circuits, (2) transformers, and (3) circuit breakers. The results of that risk analysis is the Asset Register for Risk Based Projects (<u>Confidential Attachment 2-A</u>, Confidential Appendix A).

The model uses this standard definition of risk: Risk = COF x LOF. Through a quantified risk-scoring model, each major asset that is part of the NIPSCO transmission and distribution system is scored based on the different COF and the asset's LOF with 1 being lowest and 5 highest. Additional detail on the risk scoring approach and analysis results is detailed in the Long- Term Investment Plan (Confidential Attachment 2-B), one of the building blocks of NIPSCO's 2021-2026 Electric Plan. Applications of that risk-based scoring and the results produced are used to inform the capital expenditure forecast for the system are also included in the Long-Term Investment Plan (Confidential Attachment 2-B). In short, the approach is used to allocate capital investment towards the assets with the highest risk scores.

While the COF for an asset does not necessarily change a great deal with the passage of time (unless redundancy is added to the asset base or system configurations alter the impact of the asset), the effect of infrastructure aging is that the likelihood of failure increases with each year, which over time results in an unacceptable level of risk for the utility. NIPSCO's 2021-2026 Electric Plan will reduce that risk in an efficient and orderly manner. It is important to note that the Plan has model constraints that consider NIPSCO's operational limits. The following is a hypothetical example of a model constraint:

- Based on risk alone, the model may recommend 100 breaker replacements in a year.
- NIPSCO's electric system requirements can only accommodate replacement of 60 in that year to avoid unacceptable operational consequences. This is because when NIPSCO replaces circuit breakers, NIPSCO is required to tie circuits together, and there are a limited number of circuit ties that can be performed concurrently and still maintain service to customers.
- Therefore, rather than replacing the 100 breakers in a single year, NIPSCO will schedule replacement of 60 breakers by considering a variety of factors, including risk ranking, location of the individual project, and efficiencies related to performing simultaneous work at the same location or on the same asset(s).

Q54. How did NIPSCO determine the LOF for each asset?

A54. In determining the LOF, NIPSCO utilized the associated survivor curve for each category of equipment. Survivor curves are widely used by utilities as part of depreciation studies to estimate the probable average service life of different assets and to set depreciation rates in line with those lives. Service life is defined as the period in years from the initial installation to the retirement date from service as recorded in the continuing property records ("CPR") of the utility. A plot of the retirement dispersions calculated from the CPR data for each FERC account is used to determine "best fit" Iowa survivor (mortality) curves and probable life. Likelihoods of failure over the next seven years were then derived from the survivor curves by taking a "seven year forward look" on each asset's survivor curve. This approach is detailed in the Long-Term Investment Plan (Confidential Attachment 2-B). In addition, NIPSCO incorporated condition data obtained from field observations. In order to target the poorest-condition assets on its system, the TDSIC Risk Model explicitly estimates and incorporates asset condition information into the scoring of transmission and distribution system risk. This has been accomplished through development of asset health indices ("AHI") for different transmission and distribution asset types, including substation transformers and breakers. The AHI is a condition scoring algorithm used to calculate an effective age for each asset. Effective age is then used in the TDSIC Risk Model to develop an enhanced measure of transmission and distribution system risk. The benefits of incorporating asset condition information into the TDSIC Risk Model is that NIPSCO is able to target its poorest-condition assets, in addition to the most critical assets, within its 2021-2026 Electric Plan. This will help NIPSCO to reduce the likelihood of asset failures and to decrease the impact of aging infrastructure on its customers.

Finally, using the condition data, NIPSCO determined the "effective age" of each of these assets. The effective age of an asset is the result of adjusting an asset's chronological age due to relative differences in the asset's current condition as compared to an expected condition. The condition of an asset can be influenced by many factors such as operating conditions, service history, number of operations, loadings, and demand cycles. This information is gathered from NIPSCO's maintenance and testing programs and includes information and data from analytical testing as well as visual inspections.

Q55. How did NIPSCO determine the COF for each asset?

A55. The COF was estimated through a qualitative scoring analysis involving inputs from subject matter experts, including staff involved in the design, operation, and maintenance of the asset. Multiple electric transmission and distribution planning, engineering, and operations professionals responsible for each part of the system—transmission, sub-transmission, and distribution—were engaged in this scoring process. The process consisted of a series of criticality workshops including brainstorming sessions and several follow-up meetings and discussions to finalize the consequence criteria for each part of the system. The consequence criteria were determined for each asset within each system. The criteria consider a number of factors related to an asset failure on the system and are categorized into (1) Customers Served/Lost, (2) Loss of Generation, (3) Reliability, (4) Safety and Environmental, and (5) Customer Type.

Each of these criteria were rated by NIPSCO staff on a scale of 1 to 5 (low to high) based on expert experience, system knowledge, and quantifiable data that was applicable. Once tabulated, the ratings were used to calculate a consequence score on a weighted average of the criteria that varies based on the system voltage, that is, transmission, sub-transmission, and distribution. The detailed definitions for each system and asset are included in the Long-Term Investment Plan (Confidential Attachment 2-B). As with LOF, the methodology utilized to assess consequence of failure is detailed in the Long-Term Investment Plan (Confidential Attachment 2-B).

Q56. How did NIPSCO determine which projects would be included in the Risk Ranked Aging Infrastructure investments of the 2021-2026 Electric Plan?

A56. As indicated above, NIPSCO's approach in the development of the Plan was to reduce reliability risk in the most efficient manner possible. The TDSIC Risk Model (Confidential Attachment 2-B, Confidential Appendix A) provides the raw output of the risk rankings. NIPSCO used the TDSIC Risk Model results as well as system constraints to develop an optimized aging asset replacement plan, which is provided in the Asset Register for Risk Based Projects (Confidential Attachment 2-A, Confidential Appendix A). The optimization methodology used in the development of the Plan sought to achieve the greatest risk reduction possible for the dollars invested. This included moving projects earlier or later in the planning schedule to create operational and construction efficiencies.

Q57. How will NIPSCO use the TDSIC Risk Model including COF, LOF, and condition assessment to update the Plan?

A57. Each year, NIPSCO will review the risk ranked assets and update the COF, LOF, and condition assessment. The results of that review will be used to update the risk reduction optimization, and, therefore the Asset Register for Risk Based Projects (Confidential Attachment 2-A, Confidential Appendix A), which could support moving a project to best utilize TDSIC funding to reduce risk.

Q58. Are there assets that were included in the TDSIC Risk Model that were prioritized using other criteria?

A58. Yes. Some assets contained in the TDSIC Risk Model have been identified through independent criteria such as safety, documented performance issues, or the availability of spare parts. Their replacement is also considered due to constructability efficiencies gained when performing other grid modernizations. These projects include the Breakers associated with Relay and Control Modernization, Distribution Power Transformers, Circuit Performance Improvements, and Underground Cable Replacements.

Q59. Please explain why NIPSCO is not prioritizing Breakers associated with Relay and Control Modernization, Distribution Power Transformers, Circuit Performance Improvements, and Underground Cable Replacements based solely on risk rankings.

A59. Each of these assets has a specific reason why a risk-based assessment is not the best way to design the projects.

- <u>Breakers associated with Relay and Control Modernization</u>. The breakers chosen to be replaced during a system relay and protection upgrade are included if it is required to modernize the protection scheme of a circuit. The relay and modernization plan is prioritized based on NIPSCO's system needs for protection against overvoltage, overload, and short circuit conditions. These criteria are not included within the TDSIC Risk Model.

- <u>Distribution Power Transformers</u>. The Distribution Power Transformers project is intended to replace transformers that have been determined by the TDSIC Risk Model to have the highest probability of failure, regardless of the consequence of failure. NIPSCO is proactively replacing transformers that rank the highest and are at greatest risk of failing.

- Circuit Performance Improvements. The Circuit Performance Improvement projects target the worst performing circuits and taps as determined though an annual assessment. These metrics are not included in the TDSIC Risk Model.

- Underground Cable Replacement. NIPSCO's 12.5 kV underground cable system is comprised of two general types of conductor, jacketed and unjacketed. Approximately 90% of NIPSCO's underground failures have occurred within the unjacketed population because the 1970s and 1980s vintage cable is deteriorating at an accelerated rate. While the underground cable is included within the 12.5 kV circuit make-up within the TDSIC Risk Model, the model is not able to differentiate between type or vintage of material in the underground circuit, which could allow a poor performing asset to remain on NIPSCO's system. Therefore, it is more appropriate for NIPSCO engineers to design a project to replace this cable.

Q60. Please explain the Underground Cable Replacement project [Project ID DUG1].

A60. The Plan includes approximately 253 miles of underground primary cable. The 1970s vintage underground cable has demonstrated a high rate of failure at NIPSCO. Prior cable testing indicates that cable failures in this population segment are 13% above the national average. Due to the complexity of repairs, underground cable outages are among the longest duration outages. Replacement of these segments of un-jacketed cable will reduce this known risk in the most suspect vintage cable. In addition, this replacement process will create circuit loops where radials previously existed, reducing outage duration risk for these outages. This project has a total cost estimate of approximately $103 million.

Q61. Please explain how and when NIPSCO selects the particular segments of cable to be replaced as part of the Underground Cable Replacement project.

A61. NIPSCO's asset management team uses a progressive elaboration process in evaluating its entire underground system performance utilizing outage information and additional input provided by its local operations supervisors. This analysis provides historical data on the poorest performing sections and circuits and is used to prioritize the order of replacement of the unjacketed underground cable. Sections may also be selected and placed on an accelerated schedule if they are failing at a higher than expected rate. All circuits containing cable planned for replacement in the Plan is included in the Asset Register for Non-Risk Based Projects (Confidential Attachment 2-A, Confidential Appendix B).

Q62. Please explain the Fiber Optic Cable Installation projects (included in the Relay Upgrades).

A62. The Fiber Optic Cable Installation projects are aging infrastructure investments that improve communication between protective devices, which in turn improves security and reliability of NIPSCO electric grid. The project is not evaluated as part of the TDSIC Risk Model. Selective high-speed clearance of faults on high voltage transmission lines is critical to the security of the power system. Modern system protection equipment provides more data and typically includes two-way communication across a large and well-coordinated network of devices. With older equipment, the lack of sufficient data from the device as well as the inability to communicate with many devices at the same time increases fault response times. Fiber optic cable provides the communication medium for these modern protective relay schemes. This project has a total cost estimate of $2.8 million. This does not include the fiber optic projects that were not selected to support relay upgrades. Those projects are discussed below in the grid modernization section of my testimony.

Q63. Please explain how and when NIPSCO selects the particular segments of fiber optic cable to be installed as part of the Fiber Optic Cable Installation project.

A63. Fiber optic cable installations are performed in conjunction with relay upgrades. Relay upgrades are selected and prioritized by system needs in order to protect equipment and circuits from the consequences of overvoltage, overload, and short circuit conditions. A Fiber Optic Cable Installation project will take place where existing communication paths will not support modern protective relay installations. Fiber optic cable installations will improve relay system protection of the transmission system while optically isolating the communication system from outside influences such as magnetic disturbances, lightning strikes, or other communication interruptions. These are Aging Infrastructure investments included in the Asset Register for Non-Risk Based Projects (Confidential Attachment 2-A, Confidential Appendix B).

Q64. Please explain the projects included in the Asset Register for Deliverability and Condition Based Projects.[19]

A64. An explanation of each of the other projects in this category is as follows:[20]

- The **Arrester Replacements** project [Transmission Project ID TSA1 and Distribution Project ID DSA1] is designed to replace 3-6 transmission arresters and 3-12 distribution arresters per year. The number of arresters replaced in a given year varies according to the voltage levels of the units being replaced. Arresters protect equipment from lighting and switching surges. The number of assets to be replaced each year was determined by reviewing historical trends and considering arrester replacements that would

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[19] The Steel Pole Life Extension and Wood Pole Life Extension projects have been described above but are not listed here because each asset is not listed in the Asset Register.

[20] Each project and/or applicable asset for each of these project categories has been included in the Asset Register for Non-Risk Based Projects (Confidential Attachment 2-A, Confidential Appendix B).

be included with other projects such as breaker and transformer replacements. NIPSCO will replace the assets on a proactive basis and update the replacement list as new asset health data becomes available. NIPSCO selected the particular units to be replaced in a particular year by considering age and condition data, historical model performance data, linkages to other projects, and infrared scans performed by engineers. Arresters are selected for replacement based on vintage, historical performance, condition, and criticality of protection. The arresters included in the Plan are porcelain design from the 1950s with lower protection capability and higher failure mode resulting in high velocity fragmentation when they fail, which poses potential safety concerns. Each of these arresters will be replaced with current design polymer units offering improved overvoltage protection and a non-fragmentation outer insulation. Greater transformer and breaker protection will result, as well as improving safety by eliminating the porcelain failure point.

- The **Battery and Charger Equipment Replacements** project [Transmission Project ID TSB1 and Distribution Project ID DSB1] is designed to replace 8-16 transmission batteries and chargers and 4-13 distribution batteries and chargers each year. Batteries provide the source of control power for substation equipment including relays, breakers, transformers, and communications equipment. Station batteries are critical during emergency events allowing protective devices to operate properly during abnormal operating conditions. This includes events such as transmission or distribution outages or loss of station service. Replacement batteries are determined by a combined evaluation of age and condition. Maintenance crews perform regular tests on batteries, including inter-cell and intra-cell resistance checks, specific gravity readings, and voltage tests to evaluate battery condition. The number of assets to be replaced per year was determined by reviewing historical replacement rates and the adequacy of these historical replacement rates to stay ahead of unplanned failures. NIPSCO will replace the assets on a proactive basis and update the replacement list as updated asset health data becomes available.

- The **Potential Transformer ("PT") Replacements** project [Transmission Project ID TSPT1 and Distribution Project ID DSPT1] is designed to replace 3-9 transmission potential transformers and 3-4 distribution potential transformers per year. The number of Potential Transformers replaced in a given year varies according to the voltage levels of the units being replaced. Potential transformers step down the high voltage to a level that can be utilized by relay and control equipment. The number of Potential Transformers replaced in a given year varies according to the voltage levels of the units being replaced. The number of assets to be replaced each year was determined by reviewing historical trends and considering potential transformer replacements that would be included with other projects such as breaker and transformer replacements. NIPSCO will replace the assets on a proactive basis and update the replacement list as updated asset health data becomes available. Potential transformers have been identified for replacement based upon age and condition.

- The **Substation Switch Replacements** project [Transmission Project ID TSSW1 and Distribution Project ID DSSW1] is designed to update 1-7 existing transmission and 1-4 existing substation switches and protection schemes per year. Ground switch protection schemes were commonly utilized when the system was originally constructed. Replacing these schemes with modern circuit switcher protection will improve system protection by greatly reducing overall fault clear times, reducing fault stress on power transformers, and minimizing the impacted area during a fault condition. This project involves replacing the ground switch with a circuit-switcher and upgrading and wiring the relays accordingly. This program also includes replacing other critical switches within the substation. The number of assets to be replaced each year was determined by subject matter experts considering factors such as which units would have the greatest impact and reliability improvement and how many could be completed considering constraints caused by other projects. NIPSCO selects the particular units to be replaced in a particular year by reviewing field data for problematic and very old model switches. After age, condition, and model problems are addressed, the level of substation source circuit fault current will drive the relative order of subsequent transformer ground switches to be replaced.

- The **Annunciator Replacements** project [Project ID TSRU2] is designed to replace 4 transmission annunciators in 2022. Annunciators provide local and remote indication of equipment problems. The assets to be replaced in 2022 were determined by subject matter experts determining the optimum replacement rate based on existing annunciator reliability and expected life, spare parts availability, linkages to other projects, and constraints caused by other projects. NIPSCO selects the particular units to be replaced in a particular year by reviewing age, condition, and operating history and will replace the assets on a proactive basis.

- The **Line Switch Replacements** project [Transmission Project ID TLSW1 and Distribution Project ID DLSW2] is designed to replace 4-18 transmission switches and 4-12 distribution switches each year. Switches provide positive indication that equipment is disconnected for safety and operational purposes. The number of assets to be replaced each year was determined by subject matter experts after reviewing logs of equipment operating history, equipment, age and type of switch.

- The **Distribution Power Transformers** project [Project ID DSTU1] is designed to replace the worst condition transformers or those that have an accelerated rate of degradation. Power transformers represent an asset class with the greatest lead time from manufacturers. This extended lead time increases the associated risk due to the amount of time required to replace the unit when a failure occurs. Although NIPSCO has taken steps to provide spare units through inventory or other system spare programs in the industry, the preferred method is to replace a high-risk unit prior to failure. The Distribution Power Transformer project is intended to replace transformers that have been determined by the TDSIC Risk Model to have the highest probability of failure, regardless of the consequence of failure. NIPSCO is proactively replacing transformers that rank the highest and are at greatest risk of failing. NIPSCO determined the number of transformers that are expected to actually fail each year based on subject matter experts, test data and anticipated failure rates. This project will improve system performance by removing high risk units from service through a planned event that will reduces or eliminate the need for a customer outage.

- The **Switches to Clear Incoming Lines** project [Project ID DLSW1] is designed to replace 9-42 incoming line switches per year. Incoming line switches provide a visible means to verify the incoming line to a switchgear or recloser from an incoming circuit has been disconnected from the distribution circuit. The number of assets to be replaced per year was determined by maximizing the number of replacements per year while maintaining system reliability. NIPSCO will replace the assets on a proactive basis from a list of predetermined units. NIPSCO selects the particular units to be replaced in a particular year by considering system constraints, construction efficiencies, and linkages to other projects.

SYSTEM DELIVERABILITY PROJECTS

Q65. Please describe the System Deliverability projects included in the 2021-2026 Electric Plan.

A65. Table 5 shows the System Deliverability projects included in the 2021-2026 Electric Plan.

Table 5 –System Deliverability Projects

Transmission	
Project ID	**Project Name**
TSBRU	Breaker & Relay Upgrades Projects
TSTU	Transformer Upgrade Projects
TSNRS	New/Rebuild Substation Projects
TLNRL	New/Rebuild Circuit Projects

Distribution	
Project ID	**Project Name**
DSBRU	Breaker and Relay Upgrade Projects
DSTU	Transformer Upgrade Projects
DSNRS	New Rebuild Substation Projects
DLNRL	New/Rebuild Circuit Projects

Q66. Please describe how NIPSCO identified the System Deliverability investments to include in the 2021-2026 Electric Plan.

A66. NIPSCO has reliability planning criteria and assessment practices that are used to plan for adequate system deliverability under expected peak load conditions as well as single element or contingency failure loading. Through these criteria and practices, various transmission and distribution projects are identified and evaluated to accommodate customer demands.

For the transmission system, NIPSCO's planning criteria is aligned with the North American Electric Reliability Corporation ("NERC") Reliability Standards, which includes peak load analyses along with other study scenarios targeted at testing the system under stressful situations (e.g., multiple contingencies at the same time). For reference, NIPSCO's Transmission Planning System Assessment Methodology and Planning Criteria dated January 14, 2021, which is also posted on the Midcontinent Independent System Operator, Inc.'s ("MISO") website, is attached hereto as Attachment 2-D. These criteria help ensure a transmission system that will operate reliably and remain resilient through multiple outages without causing cascading outages or widespread load loss and can accommodate near- and long-term customer load growth. These outcomes support not only NIPSCO's customers, but also the overall reliability of the Bulk Electric System.

For the distribution system, changes in electric demand associated with current and future customer growth often times require investment in the form of expanded, upgraded or additional facilities. These investments are made to ensure sufficient system capacity is available for NIPSCO's customers under peak load conditions when the system is stressed. The Company follows planning criteria used to identify areas of needed improvements under these peak conditions. These criteria call for mitigation plans to be developed when equipment limits are exceeded for normal system operations as well as under the single worst contingency. Distribution operating and design criteria rely on NIPSCO electric line and substation capacity capabilities are based on NIPSCO's line and substation design standards, along with specific equipment manufacturer ratings. Voltage operating criteria are based on the American National Standards

Institute ("ANSI") Standard C84.1 ("Electric Power Systems and Equipment - Voltage Ratings (60 Hertz)") and Indiana Administrative Code 170 IAC 4-1-20 (Standard Voltage and Permissible Voltage Variation).

The transmission and distribution planning processes both utilize industry recognized power system modeling and analysis software to perform their annual system assessments based on data collected by NIPSCO on a routine cycle. The Transmission Planning group utilizes models developed through NERC Eastern Interconnection Reliability Assessment Group (ERAG). This organization works to develop joint models that the utilities use in local transmission planning analyses. NIPSCO's Distribution Planning group utilizes models built locally utilizing NIPSCO's GIS data. Both the Transmission and Distribution Planning groups use their respective models to run scenarios that look at current and future projected conditions including load growth assumptions. These analyses consider both normal and emergency operating conditions where contingencies are introduced to stress the system to find vulnerabilities that could impact the reliability of customers' electric service. Mitigation plans are developed based on these analyses.

In addition to these simulated tests utilizing power system models, NIPSCO's electric system planners gather input from many teams within NIPSCO to validate modeled results and to capture issues that may not be identified in the simulation tests. This input includes operating data such as bus and line voltages, system equipment, current values, customer service requests (growth), and system field performance feedback from various personnel.

Q67. Please describe the 2021 and 2022 System Deliverability projects included in the 2021-2026 Electric Plan.

A67. The 2021 and 2022 Transmission System Deliverability projects include the rebuilding of two, 69 kV circuits and the extension of one, 69 kV circuit to a new Distribution Substation. The 2021 and 2022 Distribution System Deliverability projects include one new distribution substation, the addition of two new power transformers at two existing substations, replacement of one existing power transformer with a larger capacity unit, two new switchgear, the rebuilding of four, 12 kV circuits, and the reconfiguration of multiple 12 kV circuits and feeders to accommodate the aforementioned substation upgraders. These projects address system capacity issues experienced during peak load. These projects are shown on the 2021 and 2022 Project Detail pages of the Plan (Confidential Attachment 2-A, Confidential Appendix B).

Q68. Since the System Deliverability processes you described are performed annually, how did NIPSCO identify the projects for 2023-2026 to be included in the 2021-2026 Electric Plan?

A68. NIPSCO has identified and included in the Plan the System Deliverability investments that are needed in future years based on the current planning models. These projects are the product of on-going planning cycle iterations. The project detail will be provided in a future plan update. It is important to note that these improvements might change in subsequent planning cycles as NIPSCO's transmission and distribution system changes and as new or growing customers are accommodated. In the subsequent years, NIPSCO anticipates replacing or upgrading existing substation equipment including transformers, breakers, relays, disconnect switches and other associated equipment and adding new substations as demonstrated by the planning process. NIPSCO also anticipates re-conductoring existing circuits, replacing existing switches with increased capacity units, as well as adding new circuits. In addition to the specific line projects included in the Plan for 2021 and 2022, NIPSCO anticipates the construction of one new 138 kV circuit in 2024 and five new 69 kV circuits – two in 2024 and three in 2025. In addition to the specific substation projects included in the Plan for 2021 and 2022, NIPSCO anticipates the construction of a total of three new distribution substations – one in 2024 and two in 2026. NIPSCO has also identified the need to construct two new transmission substations which are currently planned in 2025 and 2026. NIPSCO anticipates and has included line construction work associated with substation source and feeder line extensions and upgrades necessary to integrate the new substations in the targeted growth areas.

GRID MODERNIZATION PROJECTS

Q69. Please describe the general Grid Modernization category and the associated benefits.

A69. NIPSCO developed a series of strategic initiatives designed to develop and enhance the NIPSCO electric system infrastructure. These initiatives are designed to achieve significant improvements in customer service and electric service reliability, as well as ensure NIPSCO is positioned to offer the services customers will expect from a modern utility. Part of the strategic initiatives includes a new, more robust telecommunications network, and implementation of modern sensing equipment (i.e., DA, SA, and AMI). The telecommunications network and modern sensing equipment will work together with a new DSCADA system to create a network that can identify and isolate faults then restore customers (self-heal). Through the incorporation of Grid Modernization technologies, NIPSCO will be able to provide value to its customers through reduced outage severity and duration improving the customer experience.

Q70. Please describe the Grid Modernization projects included in the 2021-2026 Electric Plan.

A70. The Grid Modernization initiative of DA targets the enhanced reliability of NIPSCO's distribution circuits. This program includes replacement or addition of circuit reclosers and communication equipment. The DA program, which extends beyond 2026, will strategically place approximately 600-700 electronic reclosers on existing circuits over the span of the Grid Modernization initiative. During the course of the 2021-2026 Electric Plan, approximately 515 electronic reclosers will be installed. These reclosers will be configured for either automated or manual operation aiming to split the circuits into segments that serve approximately 500 customers. NIPSCO is employing a distribution network management system that utilizes a centralized model. Each substation will have a remote terminal unit (RTU) updated or added as a data consolidation and control point for the new centralized model. DA is a dedicated program; however, these technologies are also being implemented on other aging infrastructure and deliverability projects.

The Grid Modernization initiative of SA targets the enhance reliability of NIPSCO's T&D system, as well as improves the visibility into the health of its substation assets. SA is comprised of three categories: transformer monitoring, breaker monitoring/control, and battery monitoring. Transformer monitors will allow for continuous oil analysis and temperature monitoring. Battery monitors will collect data and analyze the health of the batteries. Both of these monitors will allow NIPSCO to gain better health data on the assets allowing for more proactive maintenance and/or replacement. Distribution class relays on circuits that are receiving DA reclosers will be upgraded to microprocessor relays to better coordinate with the DA reclosers. Similar to the transformer and battery monitors, upgraded breaker relays will allow for better health data on the assets allowing for more proactive maintenance and/or replacement. SA is a dedicated program, however these technologies are also being implemented on other aging infrastructure and deliverability projects.

The new grid modernization design includes comprehensive upgrades to NIPSCO's legacy communication assets (e.g., towers, radios, fiber optics, and network configuration). The design employs high capacity digital microwave radio on lattice towers and monopoles, as well as fiber optics links configured in a multi-ring network topology. Using both microwave radio and fiber optics backhaul transport to interconnect and integrate the transport rings into the overall architecture, and establish contiguous, diverse communication paths to adjacent nodes and back to the NIPSCO system control centers. The design also provides for diverse, redundant paths back to the control centers, as well as provides visibility to distribution substations that do not currently have communications connectivity. The new DSCADA system is comprised of a combination of hardware and software that work together with NIPSCO personnel in a control center. These components allow for real-time data processing and supervisory controls to enact the DA and provide NIPSCO with valuable visibility into the status and condition of the transmission and distribution systems. Table 6 shows the Grid Modernization projects included in the 2021-2026 Electric Plan.

Table 6 – Grid Modernization Projects

Transmission	
Project ID	**Project ID**
TSSA	Transmission Substation Automation
TSC	Transmission Substation – Communication
TLF	Transmission Line – Fiber Optic
Distribution	
Project ID	**Project Name**
DSSA	Distribution Substation Automation
DLDA	Distribution Line Automation
DSC1	Distribution Substation – Communication
DSC2	Distribution SCADA
DLAMI	Advanced Metering Infrastructure (AMI)

Q71. Please describe how NIPSCO identified the types of Grid Modernization investments to include in the 2021-2026 Electric Plan and their benefits.

A71. An evaluation was performed by NIPSCO that highlighted areas of investment that were foundational to the enhancement of NIPSCO's system performance and ability to serve its customers.[21] Four of the investment categories identified were DA, SA, Communication, and AMI. NIPSCO then used a combination of third party vendors and collaborative sessions with its peer utilities to establish the performance baseline for implementation of these initiatives. DA, SA, and communication upgrades were part of Electric Plan 1, but not as dedicated programs. The description

[21] In 2019, NIPSCO assessed various system improvement and modernization efforts that were currently being explored or developed by industry leaders. This effort was performed in collaboration with a McKinsey & Company consulting team.

and justification for AMI investments are detailed by Witness Holtz.

Q72. Please describe the process of evaluation, selection and prioritizing the DA investments.

A72. The process of evaluating and prioritizing the implementation of DA investments is detailed in the Distribution Automation Program Business Case (Confidential Attachment 2-E). The report details methodology in developing an economical implementation plan which maximizes benefits to NIPSCO's customers.

As shown in the "Indiana Utility Regulatory Commission Electric Utility Reliability Report 2019," NIPSCO has maintained its reliability performance in the over the past five years but trails several of its Indiana peer utilities. The investment into the DA program for the TDSIC 2021-2026 plan has the potential to positively impact NIPSCO's reliability performance, as does the broader grid modernization effort. While the IEEE indices referenced in this report have many drivers, weather events specific to NIPSCO's territory are a large contributor. With implementation of the DA program, there is the potential to reduce the impact of these events to NIPSCO's customers. The circuits were evaluated based upon customer count and circuit criticality (i.e., hospitals, schools). These circuits were evaluated for segmentation through the deployment of an electronic recloser. These substations were cross-referenced with existing projects to ensure upgrades were performed in a timely and efficient manner without the risk of duplication of effort.

Q73. Please describe the process of evaluation, selection, and prioritization for the SA investments.

A73. As stated before, there are three components within the SA investments. The first component is associated with the DA program. Distribution breaker relays were chosen based on the need for enhanced protective scheme coordination between substation breakers and electronic line reclosers. This also has the benefit of identifying the approximate fault location which results in faster restoration times. This need is referenced in the Distribution Automation Program Business Case (<u>Confidential Attachment 2-E</u>). The second and third components of Battery and Transformer monitors were chosen to gain more insight and health data into our assets. This allows for continuous monitoring to allow for more proactive replacement. Battery monitors are being deployed within transmission substations. There are two types of transformer monitors included in this initiative. The first type of transformer monitor will bring back data points such as temperature allowing for more efficient asset operation during periods of heavy load through predictive cooling. It also has the ability to calculate equivalent loss of life from its event history. These are being deployed on 10 MVA units or larger as they are maintained or replaced. The second is an online monitor that allows faults to be detected as early as possible by continuously assessing the levels of harmful gases in the transformer oil. This second type of monitor will be installed on our largest transmission transformers.

Q74. Please describe the process of evaluation, selection and prioritization for the Communication investments.

A74. The Communication network upgrade and expansion planning required external support due to the complexity of future system needs. S&L was engaged to audit NIPSCO's current communication network, review current industry best practices, and provide a report that outlines the needs of NIPSCO's network. This document is provided in the Long-Term Communications Plan (<u>Confidential Attachment 2-F</u>). The yearly upgrades start with the construction of the main backhaul centering around NIPSCO's communication hubs. The project plan targets substations (including microwave radio and fiber optics ring nodes) for integration into a multiple ring network topology, which will be anchored at NIPSCO's operational control centers. As the 2021-2026 Electric Plan progresses the communication expansion build-out extends outward from NIPSCO control centers, moving toward the edge of the service territory. The Communication plan will extend past the 2021-2026 Electric Plan. Similar to the other Grid Modernization efforts, Communications will also be included in any new substation projects, as has been NIPSCO's practice in Electric Plan 1.

Q75. Will NIPSCO's Grid Modernization be completed by the end of the 2021-2026 Electric Plan

A75. No. NIPSCO's Grid Modernization plan is a multi-year initiative that will extend past the end of the 2021-2026 Electric Plan. NIPSCO is not seeking Commission approval for any portion of the Grid Modernization plan that is beyond 2026 in this filing.

ECONOMIC DEVELOPMENT PROJECTS

Q76. Please describe the Economic Development projects included in the 2021-2026 Electric Plan.

A76. As discussed by Witness Becker, the 2021-2026 Electric Plan provides for targeted economic development projects in the future, although none are proposed at this time.

<u>EXECUTION OF THE 2021-2026 ELECTRIC PLAN</u>

Q77. Please describe how NIPSCO's process for execution and management of the projects included in the 2021-2026 Electric Plan.

A77. <u>Attachment 2-G</u> includes information supporting NIPSCO's execution and management of the project included in the 2021-2026 Electric Plan, including an overview of NIPSCO's (1) execution of the Plan, (2) process for managing the projects in the Plan, (3) process for managing costs in the Plan, and (4) project management principles.

Q78. Please explain how NIPSCO has addressed risks associated with the execution of the 2021-2026 Electric Plan.

A78. While any plan has a degree of execution risk, steps have been taken and plans have been put in place to mitigate risk. It is important to realize, that while the investments in the Plan are substantial, NIPSCO has experience completing these type of projects.

Safety is in the forefront as a design factor ensuring public safety and constructability and is also an integral part of project execution to ensure projects are completed without injury to employees or contract partners.

This is accomplished through training, onboarding, and job site observations. For most projects, project scopes are detailed two years in advance utilizing standard designs improving estimate accuracy. A resource plan is developed on an annual basis, leveraging internal and contract resources with a heavy reliance on unit pricing whenever practical. Material and inventory needs are forecasted and integrated in the sourcing strategy focusing on price and volume commitment, as well as product delivery and quality. These practices are used as a tool to better control commodity index price variations. Recognizing the Plan covers a 6-year period, it is not possible to completely mitigate increases in labor or commodities as market conditions change over time, but NIPSCO has taken appropriate steps to address these issues.

Effective project management processes and skills are important for efficient plan execution. NIPSCO has a Project Management Team with specific expertise in managing large projects and large scopes of work such a project groups. This team successfully managed the previous Electric Plan 1 and continues to gain experience and expertise utilizing industry standard project management techniques to ensure safety, schedule, scope and cost.

<u>ELIGIBLE IMPROVEMENTS</u>

Q79. Are all of the projects included in NIPSCO's 2021-2026 Electric Plan undertaken for purposes of safety, reliability, grid modernization, or economic development?

A79. Yes.

Q80. Are any of the projects included in the 2021-2026 Electric Plan included in NIPSCO's current base rates?

A80. No.

Q81. Does the 2021-2026 Electric Plan provide the best estimate of the cost of the eligible improvements?

A81. Yes. This is described in greater detail above and in the 2021-2026 TDSIC Investment Plan Cost Analysis (<u>Confidential Attachment 2-C</u>).

Q82. Does the public convenience and necessity require or will require the eligible improvements included in the 2021-2026 Electric Plan?

A82. Yes. The eligible improvements included in the 2021-2026 Electric Plan are required or will be required to maintain the safety, integrity, and reliability of NIPSCO's transmission and distribution systems consistent with the public convenience and necessity. This is further discussed by Witness

Becker.

Q83. Are the estimated costs of the eligible transmission and distribution system improvements included in the 2021-2026 Electric Plan justified by incremental benefits attributable to the Plan?

A83. Yes. This is described in greater detail above and in the Long-Term Investment Plan (Confidential Attachment 2-B).

CONCLUSION

Q84. Does this conclude your prepared direct testimony?

A84. Yes.

VERIFICATION

I, Charles A. Vamos, Director, Electric T&D Engineering for Northern Indiana Public Service Company LLC, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Charles A. Vamos

Date: June 1, 2021

NORTHERN INDIANA PUBLIC SERVICE COMPANY

6-YEAR ELECTRIC PLAN BY PROJECT CATEGORY

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	**Project Category**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**6-Year Total**
	Direct Capital							
	Transmission Project Category							
1	Transmission Substations	$26,096,870	$39,608,052	$57,910,125	$60,200,669	$53,860,233	$54,852,316	$292,528,265
2	Transmission Lines	$14,501,950	$41,690,816	$22,276,258	$46,049,322	$47,760,270	$68,286,845	$240,950,370
3	Total Transmission	$40,598,820	$81,298,868	$80,186,383	$106,249,991	$101,620,503	$123,139,161	$533,478,635
4								
	Distribution Project Category							
5	Underground Cable	$13,652,531	$20,632,620	$18,142,533	$17,380,921	$16,172,420	$17,659,875	$103,255,991
6	Distribution Substations	$22,361,757	$52,065,812	$63,216,937	$55,231,981	$69,847,399	$63,804,727	$326,528,613
7	Distribution Lines	$28,711,340	$68,559,440	$67,687,589	$96,366,259	$89,252,100	$82,775,448	$433,352,176
8	Total Distribution	$64,725,628	$141,257,872	$149,047,059	$168,979,161	$175,271,919	$164,240,050	$863,136,780
9								
10	**Total Direct Capital**	**$105,324,448**	**$222,556,740**	**$229,233,442**	**$275,229,152**	**$276,892,422**	**$287,379,211**	**$1,396,615,415**
11	**Indirect Capital**	**$13,692,179**	**$28,932,376**	**$29,800,350**	**$35,779,789**	**$35,996,017**	**$37,359,301**	**$181,560,012**
12	**AFUDC**	**$3,570,498**	**$7,544,672**	**$7,771,017**	**$9,330,269**	**$9,386,653**	**$9,742,161**	**$47,345,270**
13	**Total Capital**	**$122,587,125**	**$259,033,788**	**$266,804,809**	**$320,339,210**	**$322,275,092**	**$334,480,673**	**$1,625,520,697**
14	**Total O&M**	**$83,418**	**$2,329,335**	**$2,263,358**	**$2,301,811**	**$1,680,577**	**$1,356,206**	**$10,014,705**

NORTHERN INDIANA PUBLIC SERVICE COMPANY
6-YEAR ELECTRIC PLAN BY FERC ACCOUNT

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	FERC Account	2021	2022	2023	2024	2025	2026	6-Year Total
	Direct Capital							
	Transmission							
1	350 - Land & Land Rights	$0	$0	$0	$55,583	$45,131	$0	$100,714
2	352 - Structures and Improvements	$4,407,572	$6,837,303	$7,646,927	$10,035,132	$7,815,251	$5,918,546	$42,660,731
3	353 - Station Equipment	$22,122,261	$36,269,815	$37,886,783	$48,455,636	$44,506,311	$40,299,918	$229,663,896
4	354 - Towers and Fixtures	$3,577,174	$5,153,625	$8,535,615	$14,703,666	$12,269,637	$6,972,125	$51,211,842
5	355 - Poles and Fixtures	$1,051,221	$2,074,273	$1,631,082	$903,448	$900,000	$1,048,603	$7,608,627
6	356 - Overhead Conductors and Devices	$13,297,563	$24,947,913	$11,471,800	$27,914,925	$26,165,173	$41,304,630	$145,363,741
7	Total Transmission	$44,455,791	$75,282,929	$67,172,207	$102,068,390	$91,701,503	$95,543,822	$476,609,551
	Distribution							
8	303 - Software	$330,000	$5,332,432	$10,700,931	$2,054,708	$2,112,959	$1,020,396	$21,551,426
9	360 - Land & Land Rights	$256,327	$653,228	$1,324,222	$1,661,045	$2,325,333	$1,433,200	$7,653,355
10	361 - Structures and Improvements	$339,336	$1,104,300	$1,025,342	$1,702,927	$1,869,670	$1,556,374	$7,597,949
11	362 - Station Equipment	$32,290,248	$57,149,947	$60,146,484	$54,895,391	$65,679,702	$61,739,114	$331,585,259
12	364 - Poles, Towers, and Fixtures	$12,021,902	$33,610,299	$30,248,192	$24,727,810	$27,897,015	$34,729,538	$163,230,907
13	365 - Overhead Conductors and Devices	$11,083,040	$29,929,276	$18,190,874	$26,514,390	$21,150,292	$24,571,200	$131,439,073
14	367 - Underground Conductors and Devices	$2,126,579	$3,702,846	$3,199,725	$3,512,624	$3,135,359	$3,468,820	$19,088,217
15	368 - Line Transformers	$351,750	$1,037,193	$1,059,413	$1,258,924	$1,363,569	$1,332,532	$6,395,683
16	370.2 - Meters	$330,000	$430,035	$2,398,484	$31,231,566	$36,765,487	$30,951,999	$102,107,571
17	373 - Street Lighting and Signal Systems	$854,228	$1,986,399	$0	$0	$0	$0	$2,840,627
18	391.2 - Hardware/Servers	$0	$2,150,175	$1,660,489	$0	$0	$0	$3,810,664
19	397 - Communication Equipment	$885,247	$10,187,681	$32,107,079	$25,601,377	$22,891,533	$31,032,216	$122,705,133
20	Total Distribution	$60,868,657	$147,273,811	$162,061,235	$173,160,762	$185,190,919	$191,835,389	$920,005,864
21	**Total Direct Capital**	**$105,324,448**	**$222,556,740**	**$229,233,442**	**$275,229,152**	**$276,892,422**	**$287,379,211**	**$1,396,615,415**
22	**Indirect Capital**	**$13,692,179**	**$28,932,376**	**$29,800,350**	**$35,779,789**	**$35,996,017**	**$37,359,301**	**$181,560,012**
23	**AFUDC**	**$3,570,498**	**$7,544,672**	**$7,771,017**	**$9,330,269**	**$9,386,653**	**$9,742,161**	**$47,345,270**
24	**Total Capital**	**$122,587,125**	**$259,033,788**	**$266,804,809**	**$320,339,210**	**$322,275,092**	**$334,480,673**	**$1,625,520,697**

NORTHERN INDIANA PUBLIC SERVICE COMPANY
ELECTRIC 2021 PROJECT DETAIL - DIRECT CAPITAL DOLLARS ONLY

(A)	(B)	(C)	(D)	(E)	(F)
Line No.	**Project ID**	**Project Category**	**Project Driver**	**Project Title**	**Plan Project Cost (direct dollars)**
		Transmission System Investments			
		Transmission Substations			
1	TSA1	Arresters - Transmission	Aging Infrastructure	Arrester Projects - Transmission	[redacted]
2	TSB1	Batteries - Transmission	Aging Infrastructure	Battery & Charger Equipment Projects - Transmission	[redacted]
3	TSPT1	Potential Transformers- Transmission	Aging Infrastructure	Potential Transformer Projects - Transmission	[redacted]
4	TSSW1	Disconnects/Substation Switch Replacements	Aging Infrastructure	Substation Switch Projects - Transmission	[redacted]
5	TSSA1	Transmission Substation Automation	Grid Modernization	Transmission Substation Automation	[redacted]
6	TSRU29	Relay Upgrades	Aging Infrastructure	Fiber Optic - Green Acres to St. John - 13888	[redacted]
7	TSRU58	Relay Upgrades	Aging Infrastructure	Relay & Breaker Upgrades - Dune Acres to Burns Ditch - 13836 N & 13836 S	[redacted]
8	TSRU59	Relay Upgrades	Aging Infrastructure	Relay & Breaker Upgrades - Dune Acres to Mittal Burns Harbor - 13849 N & 13849 S	[redacted]
9	TSRU60	Relay Upgrades	Aging Infrastructure	Relay & Breaker Upgrades - Dune Acres to Mittal Burns Harbor - 13848 N & 13848 S	[redacted]
10	TSRU61	Relay Upgrades	Aging Infrastructure	Relay Upgrades - Green Acres to St John - 13888	[redacted]
11	TSRU62	Relay Upgrades	Aging Infrastructure	Relay Upgrades - Stillwell to Plymouth - 13896	[redacted]
12	TSRU67	Relay Upgrades	Aging Infrastructure	Relay Upgrade - Tower Road - #2 XFR	[redacted]
13	TSRU69	Relay Upgrades	Aging Infrastructure	Relay & Breaker Upgrades - Miller to Beta Steel - 13842	[redacted]
14	TSBRU19	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - St. John Upgrades (345kV & 138kV)	[redacted]
15	TSBRU20	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - Dune Acres - #3 XFR BKR	[redacted]
16	TSBRU22	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - Miller - 13810-42	[redacted]
17	TSBRU27	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - Stillwell Upgrades (69kV)	[redacted]
18	TSTU9	Transformer Upgrade/Replacement	Aging Infrastructure	Transformer Upgrade - Dune Acres #3	[redacted]
19	TSNRS17	New/Rebuild Substations- Transmission	Aging Infrastructure	New/Rebuild Substation - Green Acres - #1 & #2 138/69kV Transformers; Breaker Upgrades (138kV & 69kV)	[redacted]
20	TSNRS18	New/Rebuild Substations- Transmission	Aging Infrastructure	New/Rebuild Substation - New Michigan City Substation	[redacted]
21	TSPC1	Substation Engineering- Transmission	Aging Infrastructure	Substation Pre-construction - Transmission	[redacted]
22	TSE1	Substation Engineering- Transmission	Aging Infrastructure	Substation Engineering - Transmission	[redacted]
23				**Total Transmission Substations**	[redacted]
		Transmission Lines			[redacted]
24	TLSW1	Line Switch Replacement	Aging Infrastructure	Line Switch Projects - Transmission	[redacted]
25	TLST1	Steel Structure Program	Aging Infrastructure	Steel Structure Life Extension Projects - Transmission	[redacted]
26	TLNRL6	New/Rebuild Line	Aging Infrastructure	Circuit 3465 Rebuild - 69kV Laporte JCT to Tee Lake	[redacted]
27	TLNRL9	New/Rebuild Line	Aging Infrastructure	Circuit 3465 Rebuild - New Carlisle to Olive	[redacted]
28	TLNRL19	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Monticello - 6907 - Phase 2	[redacted]
29	TLNRL21	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Kosciusko - 6997 - Phase 2	[redacted]
30	TLPC1	Line Engineering- Transmission	Aging Infrastructure	Line Pre-construction - Transmission	[redacted]
31	TLE1	Line Engineering- Transmission	Aging Infrastructure	Line Engineering - Transmission	[redacted]
32				**Total Transmission Lines**	[redacted]
33		**Total Transmission Investment**			**$40,598,820**

NORTHERN INDIANA PUBLIC SERVICE COMPANY
ELECTRIC 2021 PROJECT DETAIL - DIRECT CAPITAL DOLLARS ONLY

(A) Line No.	(B) Project ID	(C) Project Category	(D) Project Driver	(E) Project Title	(F) Plan Project Cost (direct dollars)
		Distribution System Investments			
		Underground Cable			
34	DUG1	Underground Cable Replacement	Aging Infrastructure	Underground Cable Replacement Projects	[redacted]
35				**Total Underground Cable**	
		Distribution Substations			
36	DSA1	Arresters - Distribution	Aging Infrastructure	Arrester Projects - Distribution	
37	DSB1	Batteries- Distribution	Aging Infrastructure	Battery & Charger Equipment Projects - Distribution	
38	DSSW1	Disconnects/Substation Switch Replacements	Aging Infrastructure	Substation Switch Projects - Distribution	
39	DSFC1	Feeder Cable	Aging Infrastructure	Substation Feeder Cable Projects - Distribution	
40	DSTU1	Transformer Upgrade/Replacement	Aging Infrastructure	Power Transformer Projects - Distribution	
41	DSSA1	Distribution Substation Automation	Grid Modernization	Distribution Substation Automation	
42	DSBRU24	Breaker/Recloser Upgrades	Aging Infrastructure	Breaker Upgrade - Michigan City - #11 Transformer Breaker 34kV	
43	DSBRU25	Breaker/Recloser Upgrades	Aging Infrastructure	Breaker Upgrades - Luchtman - 34-124, 34-125	
44	DSBRU28	Breaker/Recloser Upgrades	Aging Infrastructure	Breaker Upgrades - Division - Switchgear	
45	DSBRU33	Breaker/Recloser Upgrades	Aging Infrastructure	Breaker Upgrades - Monticello - Switchgear	
46	DSTU15	Transformer Upgrade/Replacement	Aging Infrastructure	Replace Transformer - Orchard Grove - #1 Transformer	
47	DSTU18	Transformer Upgrade/Replacement	Aging Infrastructure	Replace Transformer - Bourbon #2	
48	DSTU20	Transformer Upgrade/Replacement	Aging Infrastructure	Replace Transformer - Weirick #1	
49	DSTU26	Transformer Upgrade/Replacement	Deliverability	Howe Sub - #2 Transformer & #1 Volt Regs - Inc Capacity	
50	DSNRS26	New/Rebuild Substation - Distribution	Aging Infrastructure	Rebuild Substation - Munster - #3 & #4 Transformer 138/34kV and #3 Transformer Breaker	
51	DSNRS41	New/Rebuild Substation - Distribution	Aging Infrastructure	New/Rebuild Substation - Tod - #5 Transformer & Switchgear	
52	DSPC1	Substation Engineering- Distribution	Aging Infrastructure	Substation Pre-construction - Distribution	
53	DSE1	Substation Engineering- Distribution	Aging Infrastructure	Substation Engineering - Distribution	
54				**Total Distribution Substations**	
		Distribution Lines			
55	DLCP1	Circuit Performance Improvement	Aging Infrastructure	Circuit Performance Improvement Projects - Distribution	
56	DLWP1	Wood Poles	Aging Infrastructure	Pole Replacement Projects - Distribution	
57	DLSW1	Line Switch Replacement	Aging Infrastructure	Switches to Clear Incoming Lines Projects - Distribution	
58	DLSW2	Line Switch Replacement	Aging Infrastructure	Line Switch Projects - Distribution	
59	DLDA1	Distribution Line - Distribution Automation	Aging Infrastructure	Distribution Line Automation	
60	DLLED1	LED Street Lighting	Aging Infrastructure	LED Street Lighting	
61	DLAMI1	Advanced Metering Infrastructure (AMI)	Grid Modernization	Advanced Metering Infrastructure (AMI)	
62	DLNRL24	New/Rebuild Line	Aging Infrastructure	Circuit 3433 Rebuild - Grandview to Bendix West Side	
63	DLNRL35	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Roxana - 12-316	
64	DLNRL42	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - South Hammond - 12-720	
65	DLNRL62	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Laporte 1264	
66	DLNRL63	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Woodmar 12-643	
67	DLPC1	Line Engineering- Distribution	Aging Infrastructure	Line Pre-construction - Distribution	
68	DLE1	Line Engineering- Distribution	Aging Infrastructure	Line Engineering - Distribution	
69				**Total Distribution Lines**	
70		**Total Distribution Investment**			
71		**Total T&D Investment**			**$105,324,448**
72		**Total O&M Investment**			**$83,418**

NORTHERN INDIANA PUBLIC SERVICE COMPANY
ELECTRIC 2022 PROJECT DETAIL - DIRECT CAPITAL DOLLARS ONLY

(A) Line No.	(B) Project ID	(C) Project Category	(D) Project Driver	(E) Project Title	(F) Plan Project Cost (direct dollars)
		Transmission System Investments			
		Transmission Substations			
1	TSA1	Arresters - Transmission	Aging Infrastructure	Arrester Projects - Transmission	[redacted]
2	TSB1	Batteries - Transmission	Aging Infrastructure	Battery & Charger Equipment Projects - Transmission	[redacted]
3	TSPT1	Potential Transformers- Transmission	Aging Infrastructure	Potential Transformer Projects - Transmission	[redacted]
4	TSSW1	Disconnects/Substation Switch Replacements	Aging Infrastructure	Substation Switch Projects - Transmission	[redacted]
5	TSBRU46	Breaker Upgrades	Aging Infrastructure	Capacitor & Breaker Projects - Transmission	[redacted]
6	TSC1	Transmission Substation - Communication	Grid Modernization	Comm Upgrade Projects - Transmission	[redacted]
7	TSSA1	Transmission Substation Automation	Grid Modernization	Transmission Substation Automation	[redacted]
8	TSRU2	Relay Upgrades	Aging Infrastructure	Annunciator Projects - Transmission	[redacted]
9	TSRU63	Relay Upgrades	Aging Infrastructure	Relay Upgrades - South Prairie to Westwood (Duke) - 13883	[redacted]
10	TSRU71	Relay Upgrades	Aging Infrastructure	Fiber Optic - 13806 Dune Acres to Burns Ditch	[redacted]
11	TSRU75	Relay Upgrades	Aging Infrastructure	Relay Upgrade - Monticello to Springboro -13807	[redacted]
12	TSBRU19	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - St. John Upgrades (345kV & 138kV)	[redacted]
13	TSBRU29	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - Schahfer 34516 & 34521	[redacted]
14	TSBRU31	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - Liberty Park 138kV Bus Tie, #5 XFR & #6 XFR (69kV)	[redacted]
15	TSBRU36	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - Barton Lake 69-102, Bus Tie, #1 XFR, & Cap Bank	[redacted]
16	TSBRU41	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - Starke 6905, 6919, 6961, 69kV Bus Tie, #1 XFR, & #2 XFR	[redacted]
17	TSNRS13	New/Rebuild Substations- Transmission	Aging Infrastructure	Rebuild Substation - Maple - #2 138/69kV XFR and 69kV Cap Bank	[redacted]
18	TSNRS18	New/Rebuild Substations- Transmission	Aging Infrastructure	New/Rebuild Substation - New Michigan City Substation	[redacted]
19	TSPC1	Substation Engineering- Transmission	Aging Infrastructure	Substation Pre-construction - Transmission	[redacted]
20	TSE1	Substation Engineering- Transmission	Aging Infrastructure	Substation Engineering - Transmission	[redacted]
21				**Total Transmission Substations**	[redacted]
		Transmission Lines			[redacted]
22	TLSW1	Line Switch Replacement	Aging Infrastructure	Line Switch Projects - Transmission	[redacted]
23	TLST1	Steel Structure Program	Aging Infrastructure	Steel Structure Life Extension Projects - Transmission	[redacted]
24	TLF1	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Chicago Avenue to U.S.Steel - Stockton	[redacted]
25	TLF2	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Corporate Information Service Center - Microwave to Munster	[redacted]
26	TLF3	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Corporate Information Service Center - Microwave to NiSource HQ (MW Only)	[redacted]
27	TLNRL18	New/Rebuild Line	Deliverability	Circuit 6972 Rebuild - South Chalmers - Oakdale	[redacted]
28	TLNRL26	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Kosciusko - 6998	[redacted]
29	TLNRL28	New/Rebuild Line	Deliverability	Circuit Rebuild - Kosciusko - 6982	[redacted]
30	TLNRL29	New/Rebuild Line	Deliverability	Circuit Rebuild - Palmira - Extend 2nd 69kV Source Line	[redacted]
31	TLPC1	Line Engineering- Transmission	Aging Infrastructure	Line Pre-construction - Transmission	[redacted]
32	TLE1	Line Engineering- Transmission	Aging Infrastructure	Line Engineering - Transmission	[redacted]
33				**Total Transmission Lines**	[redacted]
34		**Total Transmission Investment**			**$81,298,868**

NORTHERN INDIANA PUBLIC SERVICE COMPANY
ELECTRIC 2022 PROJECT DETAIL - DIRECT CAPITAL DOLLARS ONLY

(A) Line No.	(B) Project ID	(C) Project Category	(D) Project Driver	(E) Project Title	(F) Plan Project Cost (direct dollars)
		Distribution System Investments			
		Underground Cable			
35	DUG1	Underground Cable Replacement	Aging Infrastructure	Underground Cable Replacement Projects	[redacted]
36				**Total Underground Cable**	[redacted]
		Distribution Substations			[redacted]
37	DSA1	Arresters - Distribution	Aging Infrastructure	Arrester Projects - Distribution	[redacted]
38	DSB1	Batteries- Distribution	Aging Infrastructure	Battery & Charger Equipment Projects - Distribution	[redacted]
39	DSPT1	Potential Transformers- Distribution	Aging Infrastructure	Potential Transformer Projects - Distribution	[redacted]
40	DSSW1	Disconnects/Substation Switch Replacements	Aging Infrastructure	Substation Switch Projects - Distribution	[redacted]
41	DSFC1	Feeder Cable	Aging Infrastructure	Substation Feeder Cable Projects - Distribution	[redacted]
42	DSC1	Distribution Substation - Communication	Grid Modernization	Comm Upgrade Projects - Distribution	[redacted]
43	DSC2	Distribution Substation - Communication	Grid Modernization	New Distribution SCADA	[redacted]
44	DSSA1	Distribution Substation Automation	Grid Modernization	Distribution Substation Automation	[redacted]
45	DSBRU30	Breaker/Recloser Upgrades	Aging Infrastructure	Breaker Upgrades - Gibson - Switchgear	[redacted]
46	DSBRU39	Breaker/Recloser Upgrades	Aging Infrastructure	Breaker Upgrade - Munster - 3428, 3429, 3430, 3431	[redacted]
47	DSTU21	Transformer Upgrade/Replacement	Aging Infrastructure	Replace Transformer - Wolf Lake - #2 138/34kV XFR	[redacted]
48	DSNRS34	New/Rebuild Substation - Distribution	Deliverability	Crocker Substation New Recloser & Incoming Lines	[redacted]
49	DSNRS35	New/Rebuild Substation - Distribution	Deliverability	New/Rebuild Substation - Creston - Add 2nd Transformer, #1 & #2 Voltage Regulators, Dbl. Switchgear	[redacted]
50	DSNRS36	New/Rebuild Substation - Distribution	Aging Infrastructure	Rebuild Substation - Illinois - #1 69/12kV XFR and Switchgear Breakers	[redacted]
51	DSNRS39	New/Rebuild Substation - Distribution	Aging Infrastructure	New/Rebuild Substation - Hanover - #1 & #2 Transformer with Dbl. Switchgear	[redacted]
52	DSNRS42	New/Rebuild Substation - Distribution	Deliverability	New/Rebuild Substation - Palmira Sub - Add 2nd Transformer, New Dbl. Switchgear	[redacted]
53	DSNRS43	New/Rebuild Substation - Distribution	Aging Infrastructure	New/Rebuild Substation - Johnson - Switchgear	[redacted]
54	DSNRS44	New/Rebuild Substation - Distribution	Deliverability	New Heron Lake - New 69/12.5kV Substation	[redacted]
55	DSPC1	Substation Engineering- Distribution	Aging Infrastructure	Substation Pre-construction - Distribution	[redacted]
56	DSE1	Substation Engineering- Distribution	Aging Infrastructure	Substation Engineering - Distribution	[redacted]
57				**Total Distribution Substations**	[redacted]
		Distribution Lines			[redacted]
58	DLCP1	Circuit Performance Improvement	Aging Infrastructure	Circuit Performance Improvement Projects - Distribution	[redacted]
59	DLWP1	Wood Poles	Aging Infrastructure	Pole Replacement Projects - Distribution	[redacted]
60	DLSW1	Line Switch Replacement	Aging Infrastructure	Switches to Clear Incoming Lines Projects - Distribution	[redacted]
61	DLSW2	Line Switch Replacement	Aging Infrastructure	Line Switch Projects - Distribution	[redacted]
62	DLDA1	Distribution Line - Distribution Automation	Aging Infrastructure	Distribution Line Automation	[redacted]
63	DLLED1	LED Street Lighting	Aging Infrastructure	LED Street Lighting	[redacted]
64	DLAMI1	Advanced Metering Infrastructure (AMI)	Grid Modernization	Advanced Metering Infrastructure (AMI)	[redacted]
65	DLNRL50	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Lindbergh - 12-299	[redacted]
66	DLNRL52	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - S Hammond - 12-719	[redacted]
67	DLNRL58	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Ainsworth 12-508	[redacted]
68	DLNRL59	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Johnson 12-563	[redacted]
69	DLNRL60	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - 120th St 12-572	[redacted]
70	DLNRL61	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Madison 12-625	[redacted]
71	DLNRL78	New/Rebuild Line	Deliverability	Circuit Rebuild - Crocker New Circuit - Existing Line Reconductor	[redacted]

NORTHERN INDIANA PUBLIC SERVICE COMPANY
ELECTRIC 2022 PROJECT DETAIL - DIRECT CAPITAL DOLLARS ONLY

(A) Line No.	(B) Project ID	(C) Project Category	(D) Project Driver	(E) Project Title	(F) Plan Project Cost (direct dollars)
72	DLNRL79	New/Rebuild Line	Deliverability	Bristol 12-111 / Bonneyville 12-706 Reconductor	[redacted]
73	DLNRL85	New/Rebuild Line	Deliverability	Circuit Rebuild - Palmira - New 12.5kV Circuit Extension	[redacted]
74	DLNRL86	New/Rebuild Line	Deliverability	Broadmoor Cir. 12-502 & Fisher 12-294 - Reconductor	[redacted]
75	DLNRL87	New/Rebuild Line	Deliverability	Center Sub 12-270 - Circuit Reconductor - 0.6 miles w/69kV Overbuild	[redacted]
76	DLNRL88	New/Rebuild Line	Deliverability	Heron Lake Substation - Line Taps - Ext. 69kV Source and 12.5kV Feeder Lines	[redacted]
77	DLPC1	Line Engineering- Distribution	Aging Infrastructure	Line Pre-construction - Distribution	[redacted]
78	DLE1	Line Engineering- Distribution	Aging Infrastructure	Line Engineering - Distribution	[redacted]
79				**Total Distribution Lines**	[redacted]
80		**Total Distribution Investment**			**$141,257,872**
81		**Total T&D Investment**			**$222,556,740**
82		**Total O&M Investment**			**$2,329,335**

NORTHERN INDIANA PUBLIC SERVICE COMPANY
ELECTRIC 2023 PROJECT DETAIL - DIRECT CAPITAL DOLLARS ONLY

(A) Line No.	(B) Project ID	(C) Project Category	(D) Project Driver	(E) Project Title	(F) Plan Project Cost (direct dollars)
		Transmission System Investments			
		Transmission Substations			
1	TSA1	Arresters - Transmission	Aging Infrastructure	Arrester Projects - Transmission	[redacted]
2	TSB1	Batteries - Transmission	Aging Infrastructure	Battery & Charger Equipment Projects - Transmission	[redacted]
3	TSPT1	Potential Transformers- Transmission	Aging Infrastructure	Potential Transformer Projects - Transmission	[redacted]
4	TSSW1	Disconnects/Substation Switch Replacements	Aging Infrastructure	Substation Switch Projects - Transmission	[redacted]
5	TSBRU46	Breaker Upgrades	Aging Infrastructure	Capacitor & Breaker Projects - Transmission	[redacted]
6	TSC1	Transmission Substation - Communication	Grid Modernization	Comm Upgrade Projects - Transmission	[redacted]
7	TSSA1	Transmission Substation Automation	Grid Modernization	Transmission Substation Automation	[redacted]
8	TSRU76	Relay Upgrades	Aging Infrastructure	Relay Upgrade - WCE to Praxair # 6 - 13801	[redacted]
9	TSRU79	Relay Upgrades	Aging Infrastructure	Circuit Protection Upgrade - 13879 Dune Acres to Beta Steel	[redacted]
10	TSRU80	Relay Upgrades	Aging Infrastructure	Circuit Protection Upgrade - 13806 Dune Acres to Aetna	[redacted]
11	TSBRU26	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - East Winamac Upgrades (69kV)	[redacted]
12	TSBRU30	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - Chicago Ave. 138104, 13811, 13829, 13831, 13833-104, & 13811-29	[redacted]
13	TSBRU33	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - Plymouth 13819-#1 & 13819-21	[redacted]
14	TSNRS19	New/Rebuild Substations- Transmission	Deliverability	New Marktown 138kV Substation	[redacted]
15	TSNRS20	New/Rebuild Substations- Transmission	Aging Infrastructure	New/Rebuild Substation - Sheffield - 345/138kV XFR & 13804-#2, 13804-78, 13877-78, & 13893-#2 BRKS	[redacted]
16	TSPC1	Substation Engineering- Transmission	Aging Infrastructure	Substation Pre-construction - Transmission	[redacted]
17	TSE1	Substation Engineering- Transmission	Aging Infrastructure	Substation Engineering - Transmission	[redacted]
18				**Total Transmission Substations**	[redacted]
		Transmission Lines			[redacted]
19	TLSW1	Line Switch Replacement	Aging Infrastructure	Line Switch Projects - Transmission	[redacted]
20	TLST1	Steel Structure Program	Aging Infrastructure	Steel Structure Life Extension Projects - Transmission	[redacted]
21	TLF5	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - NiSource HQ (MW Only) to Tie St. John to Green Acres	[redacted]
22	TLF6	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Plymouth to Burr Oak	[redacted]
23	TLNRL22	New/Rebuild Line	Deliverability	Circuit Rebuild - Lagrange - 6980	[redacted]
24	TLNRL28	New/Rebuild Line	Deliverability	Circuit Rebuild - Kosciusko - 6982	[redacted]
25	TLPC1	Line Engineering- Transmission	Aging Infrastructure	Line Pre-construction - Transmission	[redacted]
26	TLE1	Line Engineering- Transmission	Aging Infrastructure	Line Engineering - Transmission	[redacted]
27				**Total Transmission Lines**	[redacted]
28		**Total Transmission Investment**			**$80,186,383**

NORTHERN INDIANA PUBLIC SERVICE COMPANY
ELECTRIC 2023 PROJECT DETAIL - DIRECT CAPITAL DOLLARS ONLY

(A) Line No.	(B) Project ID	(C) Project Category	(D) Project Driver	(E) Project Title	(F) Plan Project Cost (direct dollars)
		Distribution System Investments			
		Underground Cable			
29	DUG1	Underground Cable Replacement	Aging Infrastructure	Underground Cable Replacement Projects	[redacted]
30				**Total Underground Cable**	[redacted]
		Distribution Substations			[redacted]
31	DSA1	Arresters - Distribution	Aging Infrastructure	Arrester Projects - Distribution	[redacted]
32	DSB1	Batteries- Distribution	Aging Infrastructure	Battery & Charger Equipment Projects - Distribution	[redacted]
33	DSPT1	Potential Transformers- Distribution	Aging Infrastructure	Potential Transformer Projects - Distribution	[redacted]
34	DSSW1	Disconnects/Substation Switch Replacements	Aging Infrastructure	Substation Switch Projects - Distribution	[redacted]
35	DSC1	Distribution Substation - Communication	Grid Modernization	Comm Upgrade Projects - Distribution	[redacted]
36	DSC2	Distribution Substation - Communication	Grid Modernization	New Distribution SCADA	[redacted]
37	DSSA1	Distribution Substation Automation	Grid Modernization	Distribution Substation Automation	[redacted]
38	DSBRU34	Breaker/Recloser Upgrades	Aging Infrastructure	Breaker Upgrade - Southlake - Switchgear	[redacted]
39	DSBRU36	Breaker/Recloser Upgrades	Aging Infrastructure	Breaker Upgrade - Aetna - 3475, 34kV N. Bus, 34kV S. Bus	[redacted]
40	DSBRU47	Breaker/Recloser Upgrades	Deliverability	Maple Sub - New 12.5kV Circuit Position	[redacted]
41	DSNRS29	New/Rebuild Substation - Distribution	Aging Infrastructure	Rebuild Substation - Griffith - #1 Transformer & Switchgear	[redacted]
42	DSNRS31	New/Rebuild Substation - Distribution	Aging Infrastructure	Rebuild Substation - Woodmar - #1 Transformer & Switchgear	[redacted]
43	DSNRS45	New/Rebuild Substation - Distribution	Aging Infrastructure	New/Rebuild Substation - Novak Road - #1 Transformer & Switchgear	[redacted]
44	DSNRS46	New/Rebuild Substation - Distribution	Deliverability	New/Rebuild Substation - Pidco - #1 69/12kV Transformer & Add Second Transformer and Switchgear	[redacted]
45	DSNRS47	New/Rebuild Substation - Distribution	Aging Infrastructure	New/Rebuild Substation - Schererville - #1 & #2 Transformers and Switchgears	[redacted]
46	DSPC1	Substation Engineering- Distribution	Aging Infrastructure	Substation Pre-construction - Distribution	[redacted]
47	DSE1	Substation Engineering- Distribution	Aging Infrastructure	Substation Engineering - Distribution	[redacted]
48				**Total Distribution Substations**	[redacted]
		Distribution Lines			[redacted]
49	DLCP1	Circuit Performance Improvement	Aging Infrastructure	Circuit Performance Improvement Projects - Distribution	[redacted]
50	DLWP1	Wood Poles	Aging Infrastructure	Pole Replacement Projects - Distribution	[redacted]
51	DLSW2	Line Switch Replacement	Aging Infrastructure	Line Switch Projects - Distribution	[redacted]
52	DLDA1	Distribution Line - Distribution Automation	Aging Infrastructure	Distribution Line Automation	[redacted]
53	DLAMI1	Advanced Metering Infrastructure (AMI)	Grid Modernization	Advanced Metering Infrastructure (AMI)	[redacted]
54	DLNRL53	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - N Webster - 12-159	[redacted]
55	DLNRL57	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Tod 12-457	[redacted]
56	DLNRL64	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Elliot 12-750	[redacted]
57	DLNRL68	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Decatur - 1209	[redacted]
58	DLNRL89	New/Rebuild Line	Deliverability	Lines to Support Pidco Substation	[redacted]
59	DLNRL90	New/Rebuild Line	Deliverability	Maple Sub - New 12.5kV Circuit Line Extension	[redacted]
60	DLNRL108	New/Rebuild Line	Deliverability	Circuit Rebuild - Court - Extend New 12.5kV Circuit	[redacted]
61	DLPC1	Line Engineering- Distribution	Aging Infrastructure	Line Pre-construction - Distribution	[redacted]
62	DLE1	Line Engineering- Distribution	Aging Infrastructure	Line Engineering - Distribution	[redacted]
63				**Total Distribution Lines**	[redacted]
64		**Total Distribution Investment**			**$149,047,059**
65		**Total T&D Investment**			**$229,233,442**
66		**Total O&M Investment**			**$2,263,358**

NORTHERN INDIANA PUBLIC SERVICE COMPANY
ELECTRIC 2024 PROJECT DETAIL - DIRECT CAPITAL DOLLARS ONLY

(A) Line No.	(B) Project ID	(C) Project Category	(D) Project Driver	(E) Project Title	(F) Plan Project Cost (direct dollars)
		Transmission System Investments			
		Transmission Substations			
1	TSA1	Arresters - Transmission	Aging Infrastructure	Arrester Projects - Transmission	[redacted]
2	TSB1	Batteries - Transmission	Aging Infrastructure	Battery & Charger Equipment Projects - Transmission	
3	TSPT1	Potential Transformers- Transmission	Aging Infrastructure	Potential Transformer Projects - Transmission	
4	TSSW1	Disconnects/Substation Switch Replacements	Aging Infrastructure	Substation Switch Projects - Transmission	
5	TSBRU46	Breaker Upgrades	Aging Infrastructure	Capacitor & Breaker Projects - Transmission	
6	TSC1	Transmission Substation - Communication	Grid Modernization	Comm Upgrade Projects - Transmission	
7	TSSA1	Transmission Substation Automation	Grid Modernization	Transmission Substation Automation	
8	TSRU70	Relay Upgrades	Deliverability	Relay & Breaker Upgrades - South Chalmers - Oakdale - 6971 and 6972	
9	TSRU81	Relay Upgrades	Aging Infrastructure	Relay Upgrade - Oakdale - 69kV Bus	
10	TSRU82	Relay Upgrades	Aging Infrastructure	Relay Upgrade - R. M. Schahfer - 138kV Bus	
11	TSRU83	Relay Upgrades	Aging Infrastructure	Circuit Protection Upgrade - 13890 Mittal #8 to Chicago Ave.	
12	TSRU84	Relay Upgrades	Aging Infrastructure	Relay Upgrade - R. M. Schahfer - 345kV Bus	
13	TSBRU24	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - Northport Upgrades (138kV & 69kV)	
14	TSBRU30	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - Chicago Ave. 138104, 13811, 13829, 13831, 13833-104, & 13811-29	
15	TSBRU32	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - Miller 13822	
16	TSBRU47	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - Kenwood - 138kV Bus Tie	
17	TSNRS19	New/Rebuild Substations- Transmission	Deliverability	New Marktown 138kV Substation	
18	TSNRS21	New/Rebuild Substations- Transmission	Deliverability	New St. John 138kV-69kV Substation	
19	TSNRS22	New/Rebuild Substations- Transmission	Deliverability	Veterans Hwy Sub - Add Automated 69kV Primary Changeover	
20	TSPC1	Substation Engineering- Transmission	Aging Infrastructure	Substation Pre-construction - Transmission	
21	TSE1	Substation Engineering- Transmission	Aging Infrastructure	Substation Engineering - Transmission	
22				**Total Transmission Substations**	
		Transmission Lines			
23	TLSW1	Line Switch Replacement	Aging Infrastructure	Line Switch Projects - Transmission	
24	TLST1	Steel Structure Program	Aging Infrastructure	Steel Structure Life Extension Projects - Transmission	
25	TLF7	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Broadway to Tie St. John to Green Acres	
26	TLF8	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Corporate Information Service Center - Microwave to Roxana	
27	TLF9	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Leesburg to Tie Burr Oak to Hiple	
28	TLF10	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Marktown to Mittal Steel Indiana Harbor (East) #7	
29	TLF11	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Mittal Steel Indiana Harbor (East) #5 to Mittal Steel Indiana Harbor (East) #7	
30	TLF12	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Praxair #1 - East Chicago to Marktown	
31	TLF13	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Praxair #3 - Lakeside to Tie Chicago Ave. to U.S.Steel Corp - Stockton	
32	TLF14	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Pullman Standard to Tie Corporate Information Service Center - Microwave to Roxana	
33	TLF15	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Sheffield to Marktown	
34	TLF16	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - St. John to R.M.Schahfer	
35	TLF17	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Taney to Lake George	

NORTHERN INDIANA PUBLIC SERVICE COMPANY
ELECTRIC 2024 PROJECT DETAIL - DIRECT CAPITAL DOLLARS ONLY

(A) Line No.	(B) Project ID	(C) Project Category	(D) Project Driver	(E) Project Title	(F) Plan Project Cost (direct dollars)
36	TLNRL30	New/Rebuild Line	Deliverability	Circuit Rebuild - New 138kV Line & 6990 - Hiple to Northport	[redacted]
37	TLNRL31	New/Rebuild Line	Deliverability	Liberty Park 6901 - Ext. to Veterans Hwy Sub	
38	TLNRL32	New/Rebuild Line	Deliverability	New Lines 69kV at St John Transmission Substation 69-116 & 69-117	
39	TLPC1	Line Engineering- Transmission	Aging Infrastructure	Line Pre-construction - Transmission	
40	TLE1	Line Engineering- Transmission	Aging Infrastructure	Line Engineering - Transmission	
41				**Total Transmission Lines**	
42		**Total Transmission Investment**			**$106,249,991**

NORTHERN INDIANA PUBLIC SERVICE COMPANY
ELECTRIC 2024 PROJECT DETAIL - DIRECT CAPITAL DOLLARS ONLY

(A) Line No.	(B) Project ID	(C) Project Category	(D) Project Driver	(E) Project Title	(F) Plan Project Cost (direct dollars)
		Distribution System Investments			
		Underground Cable			
43	DUG1	Underground Cable Replacement	Aging Infrastructure	Underground Cable Replacement Projects	[redacted]
44				**Total Underground Cable**	
		Distribution Substations			
45	DSA1	Arresters - Distribution	Aging Infrastructure	Arrester Projects - Distribution	
46	DSB1	Batteries- Distribution	Aging Infrastructure	Battery & Charger Equipment Projects - Distribution	
47	DSPT1	Potential Transformers- Distribution	Aging Infrastructure	Potential Transformer Projects - Distribution	
48	DSSW1	Disconnects/Substation Switch Replacements	Aging Infrastructure	Substation Switch Projects - Distribution	
49	DSC1	Distribution Substation - Communication	Grid Modernization	Comm Upgrade Projects - Distribution	
50	DSC2	Distribution Substation - Communication	Grid Modernization	New Distribution SCADA	
51	DSSA1	Distribution Substation Automation	Grid Modernization	Distribution Substation Automation	
52	DSRU9	Relay Upgrades	Aging Infrastructure	Relay Upgrade - R.M.Schahfer - #1 XFR	
53	DSBRU31	Breaker/Recloser Upgrades	Aging Infrastructure	Breaker Upgrades - Hyde Park - Switchgear	
54	DSBRU37	Breaker/Recloser Upgrades	Aging Infrastructure	Breaker Upgrade - Kenwood 34kV Upgrades	
55	DSBRU42	Breaker/Recloser Upgrades	Aging Infrastructure	Breaker Upgrade - Liable - Switchgear	
56	DSTU22	Transformer Upgrade/Replacement	Aging Infrastructure	Replace Transformer - Flint Lake - #8 138/12kV XFR	
57	DSTU24	Transformer Upgrade/Replacement	Deliverability	Transformer Replacement - Midway Sub - #1 XFR - Increase Capacity	
58	DSTU25	Transformer Upgrade/Replacement	Aging Infrastructure	Replace Transformer - Medaryville - #2 69/12kV XFR	
59	DSTU28	Transformer Upgrade/Replacement	Deliverability	Pine Creek Sub - #2 XFR - Add 2nd Set of Voltage Regulators	
60	DSTU29	Transformer Upgrade/Replacement	Deliverability	Fowler Sub - #2 XFR - Add 2nd Set of Voltage Regulators	
61	DSTU30	Transformer Upgrade/Replacement	Deliverability	Horn Ditch - Add 2nd Transformer & Upgrade 12.5kV Switchgear	
62	DSNRS22	New/Rebuild Substation - Distribution	Aging Infrastructure	Rebuild Substation - Lowell - #1 Transformer and #1 Switchgear & #2 Switchgear	
63	DSNRS48	New/Rebuild Substation - Distribution	Deliverability	New Winfield 69/12kV Substation	
64	DSNRS49	New/Rebuild Substation - Distribution	Aging Infrastructure	New/Rebuild Substation - Woodland Park - #1 Transformer & Switchgear	
65	DSPC1	Substation Engineering- Distribution	Aging Infrastructure	Substation Pre-construction - Distribution	
66	DSE1	Substation Engineering- Distribution	Aging Infrastructure	Substation Engineering - Distribution	
67				**Total Distribution Substations**	
		Distribution Lines			
68	DLCP1	Circuit Performance Improvement	Aging Infrastructure	Circuit Performance Improvement Projects - Distribution	
69	DLWP1	Wood Poles	Aging Infrastructure	Pole Replacement Projects - Distribution	
70	DLSW2	Line Switch Replacement	Aging Infrastructure	Line Switch Projects - Distribution	
71	DLDA1	Distribution Line - Distribution Automation	Aging Infrastructure	Distribution Line Automation	
72	DLAMI1	Advanced Metering Infrastructure (AMI)	Grid Modernization	Advanced Metering Infrastructure (AMI)	
73	DLNRL65	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Plymouth 1221	
74	DLNRL67	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Liable 12-332	
75	DLNRL70	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Dyer - 12-249	
76	DLNRL73	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Laporte - 1265	
77	DLNRL76	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - S. Hammond - 12-524	
78	DLNRL91	New/Rebuild Line	Deliverability	Horn Ditch Sub - 2nd 69kV Source Line	
79	DLNRL92	New/Rebuild Line	Deliverability	Horn Ditch Sub - 69kV and 12.5kV Lines	
80	DLNRL93	New/Rebuild Line	Deliverability	Hanover 12-453 - Reconductor	

NORTHERN INDIANA PUBLIC SERVICE COMPANY
ELECTRIC 2024 PROJECT DETAIL - DIRECT CAPITAL DOLLARS ONLY

(A) Line No.	(B) Project ID	(C) Project Category	(D) Project Driver	(E) Project Title	(F) Plan Project Cost (direct dollars)
81	DLNRL94	New/Rebuild Line	Deliverability	Cedar Lake 1207 & Hanover 12-453 - Reconductor	[redacted]
82	DLNRL95	New/Rebuild Line	Deliverability	Lines to Support Winfield Substation - 69kV and 12.5kV Circuit Extensions	
83	DLNRL96	New/Rebuild Line	Deliverability	Rock Run 12-382 & Model 12-432 DA Tie - Increase Capacity	
84	DLNRL97	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Broadway - 12-433	
85	DLNRL98	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Broadway - 12-437	
86	DLPC1	Line Engineering- Distribution	Aging Infrastructure	Line Pre-construction - Distribution	
87	DLE1	Line Engineering- Distribution	Aging Infrastructure	Line Engineering - Distribution	
88				**Total Distribution Lines**	
89		**Total Distribution Investment**			**$168,979,161**
90		**Total T&D Investment**			**$275,229,152**
91		**Total O&M Investment**			**$2,301,811**

NORTHERN INDIANA PUBLIC SERVICE COMPANY
ELECTRIC 2025 PROJECT DETAIL - DIRECT CAPITAL DOLLARS ONLY

(A) Line No.	(B) Project ID	(C) Project Category	(D) Project Driver	(E) Project Title	(F) Plan Project Cost (direct dollars)
		Transmission System Investments			
		Transmission Substations			
1	TSA1	Arresters - Transmission	Aging Infrastructure	Arrester Projects - Transmission	[redacted]
2	TSB1	Batteries - Transmission	Aging Infrastructure	Battery & Charger Equipment Projects - Transmission	
3	TSPT1	Potential Transformers- Transmission	Aging Infrastructure	Potential Transformer Projects - Transmission	
4	TSSW1	Disconnects/Substation Switch Replacements	Aging Infrastructure	Substation Switch Projects - Transmission	
5	TSBRU46	Breaker Upgrades	Aging Infrastructure	Capacitor & Breaker Projects - Transmission	
6	TSC1	Transmission Substation - Communication	Grid Modernization	Comm Upgrade Projects - Transmission	
7	TSSA1	Transmission Substation Automation	Grid Modernization	Transmission Substation Automation	
8	TSRU85	Relay Upgrades	Aging Infrastructure	Relay Upgrade - Chicago Ave - 138kV Bus	
9	TSRU86	Relay Upgrades	Aging Infrastructure	Relay Upgrade - Flint Lake - #3 & #4 XFR 69kV	
10	TSRU87	Relay Upgrades	Aging Infrastructure	Relay Upgrade - Flint Lake - 138kV Bus	
11	TSRU88	Relay Upgrades	Aging Infrastructure	Relay Upgrade - Kosciusko - Bus 69kV	
12	TSRU89	Relay Upgrades	Aging Infrastructure	Relay Upgrade - Maple - Bus 69kV	
13	TSRU90	Relay Upgrades	Aging Infrastructure	Relay Upgrade - Munster - 138kV Bus	
14	TSRU91	Relay Upgrades	Aging Infrastructure	Relay Upgrade - Starke - #1 XFR 69kV	
15	TSBRU30	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - Chicago Ave. 138104, 13811, 13829, 13831, 13833-104, & 13811-29	
16	TSBRU48	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - Lake George Upgrades	
17	TSTU10	Transformer Upgrade/Replacement	Aging Infrastructure	Replace Transformer - Kreitzburg - #2 138/69kV XFR	
18	TSNRS23	New/Rebuild Substations- Transmission	Deliverability	Hager Sub - 2nd 69kV Source & Primary Changeover	
19	TSNRS24	New/Rebuild Substations- Transmission	Deliverability	New/Rebuild Substation - Menges Ditch	
20	TSPC1	Substation Engineering- Transmission	Aging Infrastructure	Substation Pre-construction - Transmission	
21	TSE1	Substation Engineering- Transmission	Aging Infrastructure	Substation Engineering - Transmission	
22				**Total Transmission Substations**	
		Transmission Lines			
23	TLSW1	Line Switch Replacement	Aging Infrastructure	Line Switch Projects - Transmission	
24	TLST1	Steel Structure Program	Aging Infrastructure	Steel Structure Life Extension Projects - Transmission	
25	TLF18	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Gary Avenue to Tie Roxana to Chicago Avenue	
26	TLF19	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Green Acres to Tower Road	
27	TLF20	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Hendricks to U.S.Steel Corp - Stockton	
28	TLF21	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Mittal Steel Indiana Harbor (West) #2 to Tie Sheffield to Marktown	
29	TLF22	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Munster to Hartsdale	
30	TLF23	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Roxana to Chicago Avenue	
31	TLF24	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Starke to Burr Oak	
32	TLNRL33	New/Rebuild Line	Deliverability	Hager Sub - 2nd 69kV Source & Primary Changeover	
33	TLNRL34	New/Rebuild Line	Deliverability	New Circuits - Menges Ditch (2) 138kV Lines and (3) 69kV Lines	
34	TLPC1	Line Engineering- Transmission	Aging Infrastructure	Line Pre-construction - Transmission	
35	TLE1	Line Engineering- Transmission	Aging Infrastructure	Line Engineering - Transmission	
36				**Total Transmission Lines**	
37		**Total Transmission Investment**			**$101,620,503**

NORTHERN INDIANA PUBLIC SERVICE COMPANY
ELECTRIC 2025 PROJECT DETAIL - DIRECT CAPITAL DOLLARS ONLY

(A) Line No.	(B) Project ID	(C) Project Category	(D) Project Driver	(E) Project Title	(F) Plan Project Cost (direct dollars)
		Distribution System Investments			
		Underground Cable			
38	DUG1	Underground Cable Replacement	Aging Infrastructure	Underground Cable Replacement Projects	[redacted]
39				**Total Underground Cable**	
		Distribution Substations			
40	DSA1	Arresters - Distribution	Aging Infrastructure	Arrester Projects - Distribution	
41	DSB1	Batteries- Distribution	Aging Infrastructure	Battery & Charger Equipment Projects - Distribution	
42	DSPT1	Potential Transformers- Distribution	Aging Infrastructure	Potential Transformer Projects - Distribution	
43	DSSW1	Disconnects/Substation Switch Replacements	Aging Infrastructure	Substation Switch Projects - Distribution	
44	DSTU1	Transformer Upgrade/Replacement	Aging Infrastructure	Power Transformer Projects - Distribution	
45	DSC1	Distribution Substation - Communication	Grid Modernization	Comm Upgrade Projects - Distribution	
46	DSSA1	Distribution Substation Automation	Grid Modernization	Distribution Substation Automation	
47	DSBRU40	Breaker/Recloser Upgrades	Aging Infrastructure	Breaker Upgrade - Broadway - Switchgear	
48	DSBRU45	Breaker/Recloser Upgrades	Aging Infrastructure	Breaker Upgrade - Robertsdale - Switchgear	
49	DSBRU48	Breaker Upgrades	Deliverability	Breaker Upgrade - Wayne Substation Upgrades and #2 XFR Add Cooling Fans	
50	DSTU31	Transformer Upgrade/Replacement	Deliverability	Nealon Drive Substation - Add 2nd 34/12kV Transformer and Switchgear	
51	DSTU32	Transformer Upgrade/Replacement	Deliverability	Hanna Substation - #1 Transformer - Add Voltage Regulators	
52	DSTU33	Transformer Upgrade/Replacement	Deliverability	Hebron Substation - #1 & #2 Transformers and Voltage Regulators - Increase Capacity	
53	DSTU34	Transformer Upgrade/Replacement	Deliverability	Maplewood Substation - #1 Transformer - Increase Capacity	
54	DSTU35	Transformer Upgrade/Replacement	Deliverability	Freyer Sub - No.1 Transformer and Voltage Regulators - Increase Capacity	
55	DSTU36	Transformer Upgrade/Replacement	Deliverability	Deer Run Substation - #2 Transformer - Add 2nd Set of Voltage Regulators	
56	DSTU37	Transformer Upgrade/Replacement	Deliverability	Transformer Upgrade - Demotte - 69/12kV #1 XFR	
57	DSTU38	Transformer Upgrade/Replacement	Deliverability	Clay Substation - #1 & #2 Transformers - Increase Capacity	
58	DSTU39	Transformer Upgrade/Replacement	Deliverability	Transformer Upgrade - Maynard - #2 XFR Add Cooling Fans	
59	DSTU40	Transformer Upgrade/Replacement	Aging Infrastructure	Transformer Upgrade - Wheeler - #1 XFR Add Cooling Fans and Upgrade Bus	
60	DSNRS50	New/Rebuild Substation - Distribution	Deliverability	New/Rebuild Substation - Culver - 69/12kV #1 &#2 Transformers, Reclosers	
61	DSNRS51	New/Rebuild Substation - Distribution	Deliverability	New/Rebuild Substation - Knox - (2) 69/12kV Transformers, Reclosers	
62	DSNRS52	New/Rebuild Substation - Distribution	Aging Infrastructure	New/Rebuild Substation - Tilden - #1 & #2 XFRs and #1 & #2 Switchgears	
63	DSNRS53	New/Rebuild Substation - Distribution	Aging Infrastructure	New/Rebuild Substation - University - #1 Transformer and Switchgear	
64	DSPC1	Substation Engineering- Distribution	Aging Infrastructure	Substation Pre-construction - Distribution	
65	DSE1	Substation Engineering- Distribution	Aging Infrastructure	Substation Engineering - Distribution	
66				**Total Distribution Substations**	

NORTHERN INDIANA PUBLIC SERVICE COMPANY
ELECTRIC 2025 PROJECT DETAIL - DIRECT CAPITAL DOLLARS ONLY

(A) Line No.	(B) Project ID	(C) Project Category	(D) Project Driver	(E) Project Title	(F) Plan Project Cost (direct dollars)
		Distribution Lines			
67	DLCP1	Circuit Performance Improvement	Aging Infrastructure	Circuit Performance Improvement Projects - Distribution	[redacted]
68	DLWP1	Wood Poles	Aging Infrastructure	Pole Replacement Projects - Distribution	[redacted]
69	DLSW2	Line Switch Replacement	Aging Infrastructure	Line Switch Projects - Distribution	[redacted]
70	DLDA1	Distribution Line - Distribution Automation	Aging Infrastructure	Distribution Line Automation	[redacted]
71	DLAMI1	Advanced Metering Infrastructure (AMI)	Grid Modernization	Advanced Metering Infrastructure (AMI)	[redacted]
72	DLNRL74	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Liberty Park - 12-252	[redacted]
73	DLNRL75	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Liberty Park - 12-254	[redacted]
74	DLNRL99	New/Rebuild Line	Aging Infrastructure	Line to Support Burns Ditch Substation	[redacted]
75	DLNRL100	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Fisher - 12-294	[redacted]
76	DLNRL101	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Johnson - 12-565	[redacted]
77	DLNRL102	New/Rebuild Line	Deliverability	Lines to Support Culver Substation - 69kV & 12kV	[redacted]
78	DLNRL103	New/Rebuild Line	Deliverability	Lines to Support Knox Substation - 12.5kV & 69kV Line Extensions	[redacted]
79	DLNRL104	New/Rebuild Line	Deliverability	Nealon Drive Sub - Ext. 2nd 34kV Source Line	[redacted]
80	DLNRL105	New/Rebuild Line	Deliverability	New/Rebuild Line - McCool 12-210 Reconductor	[redacted]
81	DLPC1	Line Engineering- Distribution	Aging Infrastructure	Line Pre-construction - Distribution	[redacted]
82	DLE1	Line Engineering- Distribution	Aging Infrastructure	Line Engineering - Distribution	[redacted]
83				**Total Distribution Lines**	[redacted]
84		**Total Distribution Investment**			**$175,271,919**
85		**Total T&D Investment**			**$276,892,422**
86		**Total O&M Investment**			**$1,680,577**

NORTHERN INDIANA PUBLIC SERVICE COMPANY
ELECTRIC 2026 PROJECT DETAIL - DIRECT CAPITAL DOLLARS ONLY

(A) Line No.	(B) Project ID	(C) Project Category	(D) Project Driver	(E) Project Title	(F) Plan Project Cost (direct dollars)
		Transmission System Investments			
		Transmission Substations			
1	TSA1	Arresters - Transmission	Aging Infrastructure	Arrester Projects - Transmission	[redacted]
2	TSB1	Batteries - Transmission	Aging Infrastructure	Battery & Charger Equipment Projects - Transmission	[redacted]
3	TSPT1	Potential Transformers- Transmission	Aging Infrastructure	Potential Transformer Projects - Transmission	[redacted]
4	TSSW1	Disconnects/Substation Switch Replacements	Aging Infrastructure	Substation Switch Projects - Transmission	[redacted]
5	TSBRU46	Breaker Upgrades	Aging Infrastructure	Capacitor & Breaker Projects - Transmission	[redacted]
6	TSC1	Transmission Substation - Communication	Grid Modernization	Comm Upgrade Projects - Transmission	[redacted]
7	TSSA1	Transmission Substation Automation	Grid Modernization	Transmission Substation Automation	[redacted]
8	TSRU68	Relay Upgrades	Aging Infrastructure	Relay Upgrade - Goshen Junction - #2 XFR	[redacted]
9	TSRU92	Relay Upgrades	Aging Infrastructure	Relay Upgrade - Miller - 138kV Bus	[redacted]
10	TSBRU30	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - Chicago Ave. 138104, 13811, 13829, 13831, 13833-104, & 13811-29	[redacted]
11	TSBRU37	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - Flint Lake - 69kV Breakers	[redacted]
12	TSBRU49	Breaker Upgrades	Aging Infrastructure	Breaker Upgrade - Tower Road - 34507-23 BKR	[redacted]
13	TSTU11	Transformer Upgrade/Replacement	Deliverability	Transformer Upgrade - Dekalb - 138/69kV #1 XFR	[redacted]
14	TSNRS12	New/Rebuild Substations- Transmission	Aging Infrastructure	Rebuild Substation - Goshen Junction - #1 138/69kV Transformer and 69kV Relay and Breaker Upgrades	[redacted]
15	TSNRS25	New/Rebuild Substations- Transmission	Deliverability	Northwood Substation New Changeover	[redacted]
16	TSNRS26	New/Rebuild Substations- Transmission	Deliverability	New Schrader Ditch Substation	[redacted]
17	TSPC1	Substation Engineering- Transmission	Aging Infrastructure	Substation Pre-construction - Transmission	[redacted]
18	TSE1	Substation Engineering- Transmission	Aging Infrastructure	Substation Engineering - Transmission	[redacted]
19				**Total Transmission Substations**	[redacted]
		Transmission Lines			[redacted]
20	TLSW1	Line Switch Replacement	Aging Infrastructure	Line Switch Projects - Transmission	[redacted]
21	TLST1	Steel Structure Program	Aging Infrastructure	Steel Structure Life Extension Projects - Transmission	[redacted]
22	TLF25	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Babcock to Stillwell	[redacted]
23	TLF26	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Elmwood to Tie Corporate Information Service Center - Microwave to Munster	[redacted]
24	TLF27	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Goodland Junction to Tie Goodland to Remington	[redacted]
25	TLF28	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Idaho to Aetna	[redacted]
26	TLF29	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Kosciusko to Leesburg	[redacted]
27	TLF30	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Lake George to Babcock	[redacted]
28	TLF31	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Lincoln Square to Broadway	[redacted]
29	TLF32	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Morrison Ditch to Monticello	[redacted]
30	TLF33	Transmission Line - Fiber Optic	Grid Modernization	Comm Upgrade Fiber - Nealon Drive to Burns Ditch	[redacted]
31	TLNRL24	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Thayer - 6958	[redacted]
32	TLNRL35	New/Rebuild Line	Deliverability	New 69kV Line to Support New Schrader Ditch Substation	[redacted]
33	TLNRL36	New/Rebuild Line	Deliverability	Angola-Wolcottville 6959 69kV Line - Reconductor	[redacted]
34	TLNRL37	New/Rebuild Line	Deliverability	New Northwood 69kV Source	[redacted]
35	TLPC1	Line Engineering- Transmission	Aging Infrastructure	Line Pre-construction - Transmission	[redacted]
36	TLE1	Line Engineering- Transmission	Aging Infrastructure	Line Engineering - Transmission	[redacted]
37				**Total Transmission Lines**	[redacted]
38		**Total Transmission Investment**			**$123,139,161**

NORTHERN INDIANA PUBLIC SERVICE COMPANY
ELECTRIC 2026 PROJECT DETAIL - DIRECT CAPITAL DOLLARS ONLY

(A) Line No.	(B) Project ID	(C) Project Category	(D) Project Driver	(E) Project Title	(F) Plan Project Cost (direct dollars)
		Distribution System Investments			
		Underground Cable			
39	DUG1	Underground Cable Replacement	Aging Infrastructure	Underground Cable Replacement Projects	[redacted]
40				**Total Underground Cable**	[redacted]
		Distribution Substations			[redacted]
41	DSA1	Arresters - Distribution	Aging Infrastructure	Arrester Projects - Distribution	[redacted]
42	DSB1	Batteries- Distribution	Aging Infrastructure	Battery & Charger Equipment Projects - Distribution	[redacted]
43	DSPT1	Potential Transformers- Distribution	Aging Infrastructure	Potential Transformer Projects - Distribution	[redacted]
44	DSC1	Distribution Substation - Communication	Grid Modernization	Comm Upgrade Projects - Distribution	[redacted]
45	DSSA1	Distribution Substation Automation	Grid Modernization	Distribution Substation Automation	[redacted]
46	DSTU41	Transformer Upgrade/Replacement	Deliverability	Transformer Upgrade - Kingsford Heights - #1 XFR Increase Capacity	[redacted]
47	DSTU42	Transformer Upgrade/Replacement	Deliverability	Donaldson Sub - #1 Transformer - Increase Transformer and Volt Reg. Capacities	[redacted]
48	DSTU43	Transformer Upgrade/Replacement	Deliverability	Cedar Lake Sub #2 Transformer - Increase Capacity	[redacted]
49	DSNRS30	New/Rebuild Substation - Distribution	Aging Infrastructure	Rebuild Substation - Hartsdale - #5 Transformer & #5 Switchgear	[redacted]
50	DSNRS54	New/Rebuild Substation - Distribution	Deliverability	New Chesterton 69/12.5kV Substation	[redacted]
51	DSNRS55	New/Rebuild Substation - Distribution	Deliverability	New Southwest Lake County Substation	[redacted]
52	DSNRS57	New/Rebuild Substation - Distribution	Aging Infrastructure	New/Rebuild Substation - Angola - #3 & #4 Transformers and #3 & #4 Switchgears	[redacted]
53	DSNRS58	New/Rebuild Substation - Distribution	Deliverability	New/Rebuild Substation - Court - #2 Switchgear - Replace and Add 3rd Circuit & BT	[redacted]
54	DSNRS56	New/Rebuild Substation - Distribution	Aging Infrastructure	New/Rebuild Substation - 61st Ave - #2 Transformer and #1 & #2 Switchgears	[redacted]
55	DSNRS59	New/Rebuild Substation - Distribution	Aging Infrastructure	New/Rebuild Substation - Marktown - #3 Transformer and Breaker Upgrades	[redacted]
56	DSNRS60	New/Rebuild Substation - Distribution	Aging Infrastructure	New/Rebuild Substation - Mitchell - #1 Transformer and 34kV Bus Tie	[redacted]
57	DSPC1	Substation Engineering- Distribution	Aging Infrastructure	Substation Pre-construction - Distribution	[redacted]
58	DSE1	Substation Engineering- Distribution	Aging Infrastructure	Substation Engineering - Distribution	[redacted]
59				**Total Distribution Substations**	[redacted]
		Distribution Lines			[redacted]
60	DLCP1	Circuit Performance Improvement	Aging Infrastructure	Circuit Performance Improvement Projects - Distribution	[redacted]
61	DLWP1	Wood Poles	Aging Infrastructure	Pole Replacement Projects - Distribution	[redacted]
62	DLSW2	Line Switch Replacement	Aging Infrastructure	Line Switch Projects - Distribution	[redacted]
63	DLDA1	Distribution Line - Distribution Automation	Aging Infrastructure	Distribution Line Automation	[redacted]
64	DLAMI1	Advanced Metering Infrastructure (AMI)	Grid Modernization	Advanced Metering Infrastructure (AMI)	[redacted]
65	DLNRL106	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Indiana Harbor - 12-581	[redacted]
66	DLNRL107	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Chesterton - 12-194	[redacted]
67	DLNRL110	New/Rebuild Line	Aging Infrastructure	Circuit Rebuild - Roxana - 12-454	[redacted]
68	DLNRL111	New/Rebuild Line	Deliverability	South Haven Cir 12-715 - Upgrade Capacity	[redacted]
69	DLNRL112	New/Rebuild Line	Deliverability	Hoosier Hill 12-724 Crooked Lake Tap Reconductor	[redacted]
70	DLNRL113	New/Rebuild Line	Deliverability	McCool 12-149 - Upgrade Capacity	[redacted]
71	DLNRL114	New/Rebuild Line	Deliverability	Lines to Support New Chesterton Substation - 69kV and 12.5kV Circuits - Line Extensions	[redacted]

NORTHERN INDIANA PUBLIC SERVICE COMPANY
ELECTRIC 2026 PROJECT DETAIL - DIRECT CAPITAL DOLLARS ONLY

(A) Line No.	(B) Project ID	(C) Project Category	(D) Project Driver	(E) Project Title	(F) Plan Project Cost (direct dollars)
72	DLNRL115	New/Rebuild Line	Deliverability	Lines to Support New Southwest Lake County Substation - 69kV and 12.5kV Circuits	[redacted]
73	DLPC1	Line Engineering- Distribution	Aging Infrastructure	Line Pre-construction - Distribution	[redacted]
74	DLE1	Line Engineering- Distribution	Aging Infrastructure	Line Engineering - Distribution	[redacted]
75				**Total Distribution Lines**	[redacted]
76		**Total Distribution Investment**			**$164,240,050**
77		**Total T&D Investment**			**$287,379,211**
78		**Total O&M Investment**			**$1,356,206**

NORTHERN INDIANA PUBLIC SERVICE COMPANY

ELECTRIC FILING PROJECTS YEARLY PLAN AND EXPENSES

(A) Line No.	(B) Project ID	(C) Project Category	(D) Project Title	(E) 2021	(F) 2022	(G) 2023	(H) 2024	(I) 2025	(J) 2026	(K) Total
1	TSA1	Transmission Substations	Arrester Projects - Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	TSB1	Transmission Substations	Battery & Charger Equipment Projects - Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	TSPT1	Transmission Substations	Potential Transformer Projects - Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	TSSW1	Transmission Substations	Substation Switch Projects - Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	TSBRU46	Transmission Substations	Capacitor & Breaker Projects - Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	TSC1	Transmission Substations	Comm Upgrade Projects - Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	TSSA1	Transmission Substations	Transmission Substation Automation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	TSRU2	Transmission Substations	Annunciator Projects - Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	TSRU29	Transmission Substations	Fiber Optic - Green Acres to St. John - 13888	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	TSRU58	Transmission Substations	Relay & Breaker Upgrades - Dune Acres to Burns Ditch - 13836 N & 13836 S	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	TSRU59	Transmission Substations	Relay & Breaker Upgrades - Dune Acres to Mittal Burns Harbor - 13849 N & 13849 S	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	TSRU60	Transmission Substations	Relay & Breaker Upgrades - Dune Acres to Mittal Burns Harbor - 13848 N & 13848 S	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	TSRU61	Transmission Substations	Relay Upgrades - Green Acres to St John - 13888	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	TSRU62	Transmission Substations	Relay Upgrades - Stillwell to Plymouth - 13896	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	TSRU63	Transmission Substations	Relay Upgrades - South Prairie to Westwood (Duke) - 13883	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16	TSRU67	Transmission Substations	Relay Upgrade - Tower Road - #2 XFR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	TSRU68	Transmission Substations	Relay Upgrade - Goshen Junction - #2 XFR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	TSRU69	Transmission Substations	Relay & Breaker Upgrades - Miller to Beta Steel - 13842	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	TSRU70	Transmission Substations	Relay & Breaker Upgrades - South Chalmers - Oakdale - 6971 and 6972	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	TSRU71	Transmission Substations	Fiber Optic - 13806 Dune Acres to Burns Ditch	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	TSRU75	Transmission Substations	Relay Upgrade - Monticello to Springboro -13807	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22	TSRU76	Transmission Substations	Relay Upgrade - WCE to Praxair # 6 - 13801	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
23	TSRU79	Transmission Substations	Circuit Protection Upgrade - 13879 Dune Acres to Beta Steel	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	TSRU80	Transmission Substations	Circuit Protection Upgrade - 13806 Dune Acres to Aetna	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
25	TSRU81	Transmission Substations	Relay Upgrade - Oakdale - 69kV Bus	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
26	TSRU82	Transmission Substations	Relay Upgrade - R. M. Schahfer - 138kV Bus	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
27	TSRU83	Transmission Substations	Circuit Protection Upgrade - 13890 Mittal #8 to Chicago Ave.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
28	TSRU84	Transmission Substations	Relay Upgrade - R. M. Schahfer - 345kV Bus	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
29	TSRU85	Transmission Substations	Relay Upgrade - Chicago Ave - 138kV Bus	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
30	TSRU86	Transmission Substations	Relay Upgrade - Flint Lake - #3 & #4 XFR 69kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
31	TSRU87	Transmission Substations	Relay Upgrade - Flint Lake - 138kV Bus	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
32	TSRU88	Transmission Substations	Relay Upgrade - Kosciusko - Bus 69kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
33	TSRU89	Transmission Substations	Relay Upgrade - Maple - Bus 69kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
34	TSRU90	Transmission Substations	Relay Upgrade - Munster - 138kV Bus	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
35	TSRU91	Transmission Substations	Relay Upgrade - Starke - #1 XFR 69kV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
36	TSRU92	Transmission Substations	Relay Upgrade - Miller - 138kV Bus	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
37	TSBRU19	Transmission Substations	Breaker Upgrade - St. John Upgrades (345kV & 138kV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
38	TSBRU20	Transmission Substations	Breaker Upgrade - Dune Acres - #3 XFR BKR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
39	TSBRU22	Transmission Substations	Breaker Upgrade - Miller - 13810-42	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
40	TSBRU24	Transmission Substations	Breaker Upgrade - Northport Upgrades (138kV & 69kV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
41	TSBRU26	Transmission Substations	Breaker Upgrade - East Winamac Upgrades (69kV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
42	TSBRU27	Transmission Substations	Breaker Upgrade - Stillwell Upgrades (69kV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
43	TSBRU29	Transmission Substations	Breaker Upgrade - Schahfer 34516 & 34521	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
44	TSBRU30	Transmission Substations	Breaker Upgrade - Chicago Ave. 138104, 13811, 13829, 13831, 13833-104, & 13811-29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45	TSBRU31	Transmission Substations	Breaker Upgrade - Liberty Park 138kV Bus Tie, #5 XFR & #6 XFR (69kV)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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Line No.	Project ID	Project Category	Project Title	2021	2022	2023	2024	2025	2026	Total
46	TSBRU32	Transmission Substations	Breaker Upgrade - Miller 13822	[redacted]						
47	TSBRU33	Transmission Substations	Breaker Upgrade - Plymouth 13819-#1 & 13819-21							
48	TSBRU36	Transmission Substations	Breaker Upgrade - Barton Lake 69-102, Bus Tie, #1 XFR, & Cap Bank							
49	TSBRU37	Transmission Substations	Breaker Upgrade - Flint Lake - 69kV Breakers							
50	TSBRU41	Transmission Substations	Breaker Upgrade - Starke 6905, 6919, 6961, 69kV Bus Tie, #1 XFR, & #2 XFR							
51	TSBRU47	Transmission Substations	Breaker Upgrade - Kenwood - 138kV Bus Tie							
52	TSBRU48	Transmission Substations	Breaker Upgrade - Lake George Upgrades							
53	TSBRU49	Transmission Substations	Breaker Upgrade - Tower Road - 34507-23 BKR							
54	TSTU9	Transmission Substations	Transformer Upgrade - Dune Acres #3							
55	TSTU10	Transmission Substations	Replace Transformer - Kreitzburg - #2 138/69kV XFR							
56	TSTU11	Transmission Substations	Transformer Upgrade - Dekalb - 138/69kV #1 XFR							
57	TSNRS12	Transmission Substations	Rebuild Substation - Goshen Junction - #1 138/69kV Transformer and 69kV Relay and Breaker Upgrades							
58	TSNRS13	Transmission Substations	Rebuild Substation - Maple - #2 138/69kV XFR and 69kV Cap Bank							
59	TSNRS17	Transmission Substations	New/Rebuild Substation - Green Acres - #1 & #2 138/69kV Transformers; Breaker Upgrades (138kV & 69kV)							
60	TSNRS18	Transmission Substations	New/Rebuild Substation - New Michigan City Substation							
61	TSNRS19	Transmission Substations	New Marktown 138kV Substation							
62	TSNRS20	Transmission Substations	New/Rebuild Substation - Sheffield - 345/138kV XFR & 13804-#2, 13804-78, 13877-78, & 13893-#2 BRKS							
63	TSNRS21	Transmission Substations	New St. John 138kV-69kV Substation							
64	TSNRS22	Transmission Substations	Veterans Hwy Sub - Add Automated 69kV Primary Changeover							
65	TSNRS23	Transmission Substations	Hager Sub - 2nd 69kV Source & Primary Changeover							
66	TSNRS24	Transmission Substations	New/Rebuild Substation - Menges Ditch							
67	TSNRS25	Transmission Substations	Northwood Substation New Changeover							
68	TSNRS26	Transmission Substations	New Schrader Ditch Substation							
69	TSPC1	Transmission Substations	Substation Pre-construction - Transmission							
70	TSE1	Transmission Substations	Substation Engineering - Transmission							
71	TLSW1	Transmission Lines	Line Switch Projects - Transmission							
72	TLST1	Transmission Lines	Steel Structure Life Extension Projects - Transmission							
73	TLF1	Transmission Lines	Comm Upgrade Fiber - Chicago Avenue to U.S.Steel - Stockton							
74	TLF2	Transmission Lines	Comm Upgrade Fiber - Corporate Information Service Center - Microwave to Munster							
75	TLF3	Transmission Lines	Comm Upgrade Fiber - Corporate Information Service Center - Microwave to NiSource HQ (MW Only)							
76	TLF5	Transmission Lines	Comm Upgrade Fiber - NiSource HQ (MW Only) to Tie St. John to Green Acres							
77	TLF6	Transmission Lines	Comm Upgrade Fiber - Plymouth to Burr Oak							
78	TLF7	Transmission Lines	Comm Upgrade Fiber - Broadway to Tie St. John to Green Acres							
79	TLF8	Transmission Lines	Comm Upgrade Fiber - Corporate Information Service Center - Microwave to Roxana							
80	TLF9	Transmission Lines	Comm Upgrade Fiber - Leesburg to Tie Burr Oak to Hiple							
81	TLF10	Transmission Lines	Comm Upgrade Fiber - Marktown to Mittal Steel Indiana Harbor (East) #7							
82	TLF11	Transmission Lines	Comm Upgrade Fiber - Mittal Steel Indiana Harbor (East) #5 to Mittal Steel Indiana Harbor (East) #7							
83	TLF12	Transmission Lines	Comm Upgrade Fiber - Praxair #1 - East Chicago to Marktown							
84	TLF13	Transmission Lines	Comm Upgrade Fiber - Praxair #3 - Lakeside to Tie Chicago Ave. to U.S.Steel Corp - Stockton							

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85	TLF14	Transmission Lines	Comm Upgrade Fiber - Pullman Standard to Tie Corporate Information Service Center - Microwave to Roxana	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
86	TLF15	Transmission Lines	Comm Upgrade Fiber - Sheffield to Marktown	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
87	TLF16	Transmission Lines	Comm Upgrade Fiber - St. John to R.M.Schahfer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
88	TLF17	Transmission Lines	Comm Upgrade Fiber - Taney to Lake George	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
89	TLF18	Transmission Lines	Comm Upgrade Fiber - Gary Avenue to Tie Roxana to Chicago Avenue	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
90	TLF19	Transmission Lines	Comm Upgrade Fiber - Green Acres to Tower Road	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
91	TLF20	Transmission Lines	Comm Upgrade Fiber - Hendricks to U.S.Steel Corp - Stockton	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
92	TLF21	Transmission Lines	Comm Upgrade Fiber - Mittal Steel Indiana Harbor (West) #2 to Tie Sheffield to Marktown	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
93	TLF22	Transmission Lines	Comm Upgrade Fiber - Munster to Hartsdale	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
94	TLF23	Transmission Lines	Comm Upgrade Fiber - Roxana to Chicago Avenue	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
95	TLF24	Transmission Lines	Comm Upgrade Fiber - Starke to Burr Oak	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
96	TLF25	Transmission Lines	Comm Upgrade Fiber - Babcock to Stillwell	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
97	TLF26	Transmission Lines	Comm Upgrade Fiber - Elmwood to Tie Corporate Information Service Center - Microwave to Munster	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
98	TLF27	Transmission Lines	Comm Upgrade Fiber - Goodland Junction to Tie Goodland to Remington	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
99	TLF28	Transmission Lines	Comm Upgrade Fiber - Idaho to Aetna	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
100	TLF29	Transmission Lines	Comm Upgrade Fiber - Kosciusko to Leesburg	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
101	TLF30	Transmission Lines	Comm Upgrade Fiber - Lake George to Babcock	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
102	TLF31	Transmission Lines	Comm Upgrade Fiber - Lincoln Square to Broadway	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
103	TLF32	Transmission Lines	Comm Upgrade Fiber - Morrison Ditch to Monticello	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
104	TLF33	Transmission Lines	Comm Upgrade Fiber - Nealon Drive to Burns Ditch	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
105	TLNRL6	Transmission Lines	Circuit 3465 Rebuild - 69kV Laporte JCT to Tee Lake	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
106	TLNRL9	Transmission Lines	Circuit 3465 Rebuild - New Carlisle to Olive	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
107	TLNRL18	Transmission Lines	Circuit 6972 Rebuild - South Chalmers - Oakdale	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
108	TLNRL33	Transmission Lines	Hager Sub - 2nd 69kV Source & Primary Changeover	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
109	TLNRL34	Transmission Lines	New Circuits - Menges Ditch (2) 138kV Lines and (3) 69kV Lines	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
110	TLNRL19	Transmission Lines	Circuit Rebuild - Monticello - 6907 - Phase 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
111	TLNRL21	Transmission Lines	Circuit Rebuild - Kosciusko - 6997 - Phase 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
112	TLNRL22	Transmission Lines	Circuit Rebuild - Lagrange - 6980	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
113	TLNRL24	Transmission Lines	Circuit Rebuild - Thayer - 6958	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
114	TLNRL26	Transmission Lines	Circuit Rebuild - Kosciusko - 6998	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
115	TLNRL28	Transmission Lines	Circuit Rebuild - Kosciusko - 6982	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
116	TLNRL29	Transmission Lines	Circuit Rebuild - Palmira - Extend 2nd 69kV Source Line	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
117	TLNRL30	Transmission Lines	Circuit Rebuild - New 138kV Line & 6990 - Hiple to Northport	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
118	TLNRL31	Transmission Lines	Liberty Park 6901 - Ext. to Veterans Hwy Sub	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
119	TLNRL32	Transmission Lines	New Lines 69kV at St John Transmission Substation 69-116 & 69-117	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
120	TLNRL35	Transmission Lines	New 69kV Line to Support New Schrader Ditch Substation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
121	TLNRL36	Transmission Lines	Angola-Wolcottville 6959 69kV Line - Reconductor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
122	TLNRL37	Transmission Lines	New Northwood 69kV Source	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
123	TLPC1	Transmission Lines	Line Pre-construction - Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
124	TLE1	Transmission Lines	Line Engineering - Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
125	DUG1	Underground Cable	Underground Cable Replacement Projects	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
126	DSA1	Distribution Substations	Arrester Projects - Distribution	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
127	DSB1	Distribution Substations	Battery & Charger Equipment Projects - Distribution	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
128	DSPT1	Distribution Substations	Potential Transformer Projects - Distribution	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
129	DSSW1	Distribution Substations	Substation Switch Projects - Distribution	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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130	DSFC1	Distribution Substations	Substation Feeder Cable Projects - Distribution	[redacted]						
131	DSTU1	Distribution Substations	Power Transformer Projects - Distribution							
132	DSC1	Distribution Substations	Comm Upgrade Projects - Distribution							
133	DSC2	Distribution Substations	New Distribution SCADA							
134	DSSA1	Distribution Substations	Distribution Substation Automation							
135	DSRU9	Distribution Substations	Relay Upgrade - R.M.Schahfer - #1 XFR							
136	DSBRU24	Distribution Substations	Breaker Upgrade - Michigan City - #11 Transformer Breaker 34kV							
137	DSBRU25	Distribution Substations	Breaker Upgrades - Luchtman - 34-124, 34-125							
138	DSBRU28	Distribution Substations	Breaker Upgrades - Division - Switchgear							
139	DSBRU30	Distribution Substations	Breaker Upgrades - Gibson - Switchgear							
140	DSBRU31	Distribution Substations	Breaker Upgrades - Hyde Park - Switchgear							
141	DSBRU33	Distribution Substations	Breaker Upgrades - Monticello - Switchgear							
142	DSBRU34	Distribution Substations	Breaker Upgrade - Southlake - Switchgear							
143	DSBRU36	Distribution Substations	Breaker Upgrade - Aetna - 3475, 34kV N. Bus, 34kV S. Bus							
144	DSBRU37	Distribution Substations	Breaker Upgrade - Kenwood 34kV Upgrades							
145	DSBRU39	Distribution Substations	Breaker Upgrade - Munster - 3428, 3429, 3430, 3431							
146	DSBRU40	Distribution Substations	Breaker Upgrade - Broadway - Switchgear							
147	DSBRU42	Distribution Substations	Breaker Upgrade - Liable - Switchgear							
148	DSBRU45	Distribution Substations	Breaker Upgrade - Robertsdale - Switchgear							
149	DSBRU47	Distribution Substations	Maple Sub - New 12.5kV Circuit Position							
150	DSBRU48	Transmission Substations	Breaker Upgrade - Wayne Substation Upgrades and #2 XFR Add Cooling Fans							
151	DSTU15	Distribution Substations	Replace Transformer - Orchard Grove - #1 Transformer							
152	DSTU18	Distribution Substations	Replace Transformer - Bourbon #2							
153	DSTU20	Distribution Substations	Replace Transformer - Weirick #1							
154	DSTU21	Distribution Substations	Replace Transformer - Wolf Lake - #2 138/34kV XFR							
155	DSTU22	Distribution Substations	Replace Transformer - Flint Lake - #8 138/12kV XFR							
156	DSTU24	Distribution Substations	Transformer Replacement - Midway Sub - #1 XFR - Increase Capacity							
157	DSTU25	Distribution Substations	Replace Transformer - Medaryville - #2 69/12kV XFR							
158	DSTU26	Distribution Substations	Howe Sub - #2 Transformer & #1 Volt Regs - Inc Capacity							
159	DSTU28	Distribution Substations	Pine Creek Sub - #2 XFR - Add 2nd Set of Voltage Regulators							
160	DSTU29	Distribution Substations	Fowler Sub - #2 XFR - Add 2nd Set of Voltage Regulators							
161	DSTU30	Distribution Substations	Horn Ditch - Add 2nd Transformer & Upgrade 12.5kV Switchgear							
162	DSTU31	Distribution Substations	Nealon Drive Substation - Add 2nd 34/12kV Transformer and Switchgear							
163	DSTU32	Distribution Substations	Hanna Substation - #1 Transformer - Add Voltage Regulators							
164	DSTU33	Distribution Substations	Hebron Substation - #1 & #2 Transformers and Voltage Regulators - Increase Capacity							
165	DSTU34	Distribution Substations	Maplewood Substation - #1 Transformer - Increase Capacity							
166	DSTU35	Distribution Substations	Freyer Sub - No.1 Transformer and Voltage Regulators - Increase Capacity							
167	DSTU36	Distribution Substations	Deer Run Substation - #2 Transformer - Add 2nd Set of Voltage Regulators							
168	DSTU37	Distribution Substations	Transformer Upgrade - Demotte - 69/12kV #1 XFR							
169	DSTU38	Distribution Substations	Clay Substation - #1 & #2 Transformers - Increase Capacity							
170	DSTU39	Distribution Substations	Transformer Upgrade - Maynard - #2 XFR Add Cooling Fans							
171	DSTU40	Distribution Substations	Transformer Upgrade - Wheeler - #1 XFR Add Cooling Fans and Upgrade Bus							
172	DSTU41	Distribution Substations	Transformer Upgrade - Kingsford Heights - #1 XFR Increase Capacity							

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173	DSTU42	Distribution Substations	Donaldson Sub - #1 Transformer - Increase Transformer and Volt Reg. Capacities	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
174	DSTU43	Distribution Substations	Cedar Lake Sub #2 Transformer - Increase Capacity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
175	DSNRS22	Distribution Substations	Rebuild Substation - Lowell - #1 Transformer and #1 Switchgear & #2 Switchgear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
176	DSNRS26	Distribution Substations	Rebuild Substation - Munster - #3 & #4 Transformer 138/34kV and #3 Transformer Breaker	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
177	DSNRS29	Distribution Substations	Rebuild Substation - Griffith - #1 Transformer & Switchgear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
178	DSNRS30	Distribution Substations	Rebuild Substation - Hartsdale - #5 Transformer & #5 Switchgear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
179	DSNRS31	Distribution Substations	Rebuild Substation - Woodmar - #1 Transformer & Switchgear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
180	DSNRS34	Distribution Substations	Crocker Substation New Recloser & Incoming Lines	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
181	DSNRS35	Distribution Substations	New/Rebuild Substation - Creston - Add 2nd Transformer, #1 & #2 Voltage Regulators, Dbl. Switchgear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
182	DSNRS36	Distribution Substations	Rebuild Substation - Illinois - #1 69/12kV XFR and Switchgear Breakers	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
183	DSNRS39	Distribution Substations	New/Rebuild Substation - Hanover - #1 & #2 Transformer with Dbl. Switchgear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
184	DSNRS41	Distribution Substations	New/Rebuild Substation - Tod - #5 Transformer & Switchgear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
185	DSNRS42	Distribution Substations	New/Rebuild Substation - Palmira Sub - Add 2nd Transformer, New Dbl. Switchgear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
186	DSNRS43	Distribution Substations	New/Rebuild Substation - Johnson - Switchgear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
187	DSNRS44	Distribution Substations	New Heron Lake - New 69/12 5kV Substation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
188	DSNRS45	Distribution Substations	New/Rebuild Substation - Novak Road - #1 Transformer & Switchgear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
189	DSNRS46	Distribution Substations	New/Rebuild Substation - Pidco - #1 69/12kV Transformer & Add Second Transformer and Switchgear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
190	DSNRS47	Distribution Substations	New/Rebuild Substation - Schererville - #1 & #2 Transformers and Switchgears	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
191	DSNRS48	Distribution Substations	New Winfield 69/12kV Substation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
192	DSNRS49	Distribution Substations	New/Rebuild Substation - Woodland Park - #1 Transformer & Switchgear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
193	DSNRS50	Distribution Substations	New/Rebuild Substation - Culver - 69/12kV #1 &#2 Transformers, Reclosers	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
194	DSNRS51	Distribution Substations	New/Rebuild Substation - Knox - (2) 69/12kV Transformers, Reclosers	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
195	DSNRS52	Distribution Substations	New/Rebuild Substation - Tilden - #1 & #2 XFRs and #1 & #2 Switchgears	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
196	DSNRS53	Distribution Substations	New/Rebuild Substation - University - #1 Transformer and Switchgear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
197	DSNRS54	Distribution Substations	New Chesterton 69/12.5kV Substation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
198	DSNRS55	Distribution Substations	New Southwest Lake County Substation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
199	DSNRS57	Distribution Substations	New/Rebuild Substation - Angola - #3 & #4 Transformers and #3 & #4 Switchgears	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
200	DSNRS58	Distribution Substations	New/Rebuild Substation - Court - #2 Switchgear - Replace and Add 3rd Circuit & BT	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
201	DSNRS56	Distribution Substations	New/Rebuild Substation - 61st Ave - #2 Transformer and #1 & #2 Switchgears	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
202	DSNRS59	Distribution Substations	New/Rebuild Substation - Marktown - #3 Transformer and Breaker Upgrades	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
203	DSNRS60	Distribution Substations	New/Rebuild Substation - Mitchell - #1 Transformer and 34kV Bus Tie	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

NORTHERN INDIANA PUBLIC SERVICE COMPANY
ELECTRIC FILING PROJECTS YEARLY PLAN AND EXPENSES

(A) Line No.	(B) Project ID	(C) Project Category	(D) Project Title	(E) 2021	(F) 2022	(G) 2023	(H) 2024	(I) 2025	(J) 2026	(K) Total
204	DSPC1	Distribution Substations	Substation Pre-construction - Distribution	[redacted]						
205	DSE1	Distribution Substations	Substation Engineering - Distribution							
206	DLCP1	Distribution Lines	Circuit Performance Improvement Projects - Distribution							
207	DLWP1	Distribution Lines	Pole Replacement Projects - Distribution							
208	DLSW1	Distribution Lines	Switches to Clear Incoming Lines Projects - Distribution							
209	DLSW2	Distribution Lines	Line Switch Projects - Distribution							
210	DLDA1	Distribution Lines	Distribution Line Automation							
211	DLLED1	Distribution Lines	LED Street Lighting							
212	DLAMI1	Distribution Lines	Advanced Metering Infrastructure (AMI)							
213	DLNRL24	Distribution Lines	Circuit 3433 Rebuild - Grandview to Bendix West Side							
214	DLNRL35	Distribution Lines	Circuit Rebuild - Roxana - 12-316							
215	DLNRL42	Distribution Lines	Circuit Rebuild - South Hammond - 12-720							
216	DLNRL50	Distribution Lines	Circuit Rebuild - Lindbergh - 12-299							
217	DLNRL52	Distribution Lines	Circuit Rebuild - S Hammond - 12-719							
218	DLNRL53	Distribution Lines	Circuit Rebuild - N Webster - 12-159							
219	DLNRL57	Distribution Lines	Circuit Rebuild - Tod 12-457							
220	DLNRL58	Distribution Lines	Circuit Rebuild - Ainsworth 12-508							
221	DLNRL59	Distribution Lines	Circuit Rebuild - Johnson 12-563							
222	DLNRL60	Distribution Lines	Circuit Rebuild - 120th St 12-572							
223	DLNRL61	Distribution Lines	Circuit Rebuild - Madison 12-625							
224	DLNRL62	Distribution Lines	Circuit Rebuild - Laporte 1264							
225	DLNRL63	Distribution Lines	Circuit Rebuild - Woodmar 12-643							
226	DLNRL64	Distribution Lines	Circuit Rebuild - Elliot 12-750							
227	DLNRL65	Distribution Lines	Circuit Rebuild - Plymouth 1221							
228	DLNRL67	Distribution Lines	Circuit Rebuild - Liable 12-332							
229	DLNRL68	Distribution Lines	Circuit Rebuild - Decatur - 1209							
230	DLNRL70	Distribution Lines	Circuit Rebuild - Dyer - 12-249							
231	DLNRL73	Distribution Lines	Circuit Rebuild - Laporte - 1265							
232	DLNRL74	Distribution Lines	Circuit Rebuild - Liberty Park - 12-252							
233	DLNRL75	Distribution Lines	Circuit Rebuild - Liberty Park - 12-254							
234	DLNRL76	Distribution Lines	Circuit Rebuild - S. Hammond - 12-524							
235	DLNRL78	Distribution Lines	Circuit Rebuild - Crocker New Circuit - Existing Line Reconductor							
236	DLNRL79	Distribution Lines	Bristol 12-111 / Bonneyville 12-706 Reconductor							
237	DLNRL85	Distribution Lines	Circuit Rebuild - Palmira - New 12.5kV Circuit Extension							
238	DLNRL86	Distribution Lines	Broadmoor Cir. 12-502 & Fisher 12-294 - Reconductor							
239	DLNRL87	Distribution Lines	Center Sub 12-270 - Circuit Reconductor - 0.6 miles w/69kV Overbuild							
240	DLNRL88	Distribution Lines	Heron Lake Substation - Line Taps - Ext. 69kV Source and 12.5kV Feeder Lines							
241	DLNRL89	Distribution Lines	Lines to Support Pidco Substation							
242	DLNRL90	Distribution Lines	Maple Sub - New 12.5kV Circuit Line Extension							
243	DLNRL91	Distribution Lines	Horn Ditch Sub - 2nd 69kV Source Line							
244	DLNRL92	Distribution Lines	Horn Ditch Sub - 69kV and 12.5kV Lines							
245	DLNRL93	Distribution Lines	Hanover 12-453 - Reconductor							
246	DLNRL94	Distribution Lines	Cedar Lake 1207 & Hanover 12-453 - Reconductor							
247	DLNRL95	Distribution Lines	Lines to Support Winfield Substation - 69kV and 12 5kV Circuit Extensions							
248	DLNRL96	Distribution Lines	Rock Run 12-382 & Model 12-432 DA Tie - Increase Capacity							
249	DLNRL97	Distribution Lines	Circuit Rebuild - Broadway - 12-433							
250	DLNRL98	Distribution Lines	Circuit Rebuild - Broadway - 12-437							
251	DLNRL99	Distribution Lines	Line to Support Burns Ditch Substation							

NORTHERN INDIANA PUBLIC SERVICE COMPANY

ELECTRIC FILING PROJECTS YEARLY PLAN AND EXPENSES

(A) Line No.	(B) Project ID	(C) Project Category	(D) Project Title	(E) 2021	(F) 2022	(G) 2023	(H) 2024	(I) 2025	(J) 2026	(K) Total
252	DLNRL100	Distribution Lines	Circuit Rebuild - Fisher - 12-294	[redacted]						
253	DLNRL101	Distribution Lines	Circuit Rebuild - Johnson - 12-565	[redacted]						
254	DLNRL102	Distribution Lines	Lines to Support Culver Substation - 69kV & 12kV	[redacted]						
255	DLNRL103	Distribution Lines	Lines to Support Knox Substation - 12 5kV & 69kV Line Extensions	[redacted]						
256	DLNRL104	Distribution Lines	Nealon Drive Sub - Ext. 2nd 34kV Source Line	[redacted]						
257	DLNRL105	Distribution Lines	New/Rebuild Line - McCool 12-210 Reconductor	[redacted]						
258	DLNRL106	Distribution Lines	Circuit Rebuild - Indiana Harbor - 12-581	[redacted]						
259	DLNRL107	Distribution Lines	Circuit Rebuild - Chesterton - 12-194	[redacted]						
260	DLNRL108	Distribution Lines	Circuit Rebuild - Court - Extend New 12.5kV Circuit	[redacted]						
261	DLNRL110	Distribution Lines	Circuit Rebuild - Roxana - 12-454	[redacted]						
262	DLNRL111	Distribution Lines	South Haven Cir 12-715 - Upgrade Capacity	[redacted]						
263	DLNRL112	Distribution Lines	Hoosier Hill 12-724 Crooked Lake Tap Reconductor	[redacted]						
264	DLNRL113	Distribution Lines	McCool 12-149 - Upgrade Capacity	[redacted]						
265	DLNRL114	Distribution Lines	Lines to Support New Chesterton Substation - 69kV and 12.5kV Circuits - Line Extensions	[redacted]						
266	DLNRL115	Distribution Lines	Lines to Support New Southwest Lake County Substation - 69kV and 12.5kV Circuits	[redacted]						
267	DLPC1	Distribution Lines	Line Pre-construction - Distribution	[redacted]						
268	DLE1	Distribution Lines	Line Engineering - Distribution	[redacted]						
269		Total Direct Capital		$ 105,324,448	$ 222,556,740	$ 229,233,442	$ 275,229,152	$ 276,892,422	$ 287,379,211	$ 1,396,615,415

Summary by Project Category

Line No.	Project ID	Project Category	Project Title	2021	2022	2023	2024	2025	2026	Total
270		Transmission Substations		$ 26,096,870	$ 39,608,052	$ 57,910,125	$ 60,200,669	$ 54,908,149	$ 54,852,316	$ 293,576,181
271		Transmission Lines		$ 14,501,950	$ 41,690,816	$ 22,276,258	$ 46,049,322	$ 47,760,270	$ 68,286,845	$ 240,565,461
272		Underground Cable		$ 13,652,531	$ 20,632,620	$ 18,142,533	$ 17,380,921	$ 16,172,420	$ 17,659,875	$ 103,640,900
273		Distribution Substations		$ 22,361,757	$ 52,065,812	$ 63,216,937	$ 55,231,981	$ 68,799,483	$ 63,804,727	$ 325,480,697
274		Distribution Lines		$ 28,711,340	$ 68,559,440	$ 67,687,589	$ 96,366,259	$ 89,252,100	$ 82,775,448	$ 433,352,176
275		Total Direct Capital		$ 105,324,448	$ 222,556,740	$ 229,233,442	$ 275,229,152	$ 276,892,422	$ 287,379,211	$ 1,396,615,415
276		Transmission Total		$ 40,598,820	$ 81,298,868	$ 80,186,383	$ 106,249,991	$ 102,668,419	$ 123,139,161	$ 534,141,642
277		Distribution Total		$ 64,725,628	$ 141,257,872	$ 149,047,059	$ 168,979,161	$ 174,224,003	$ 164,240,050	$ 862,473,773
278		Total Direct Capital		$ 105,324,448	$ 222,556,740	$ 229,233,442	$ 275,229,152	$ 276,892,422	$ 287,379,211	$ 1,396,615,415

Confidential Attachment 2-B (Redacted)

[2021-2026 TDSIC Investment Plan Business Case]

Confidential Attachment 2-C (Redacted)

[2021-2026 TDSIC Investment Plan Cost Analysis]

TRANSMISSION PLANNING ASSESSMENT METHODOLOGY AND CRITERIA

For Compliance with NERC Reliability Standard: TPL-001-4

1/14/2021
Version: 4.8

Table of Contents

1 REVISION AND APPROVAL HISTORY

This document shall be revised and updated as needed to incorporate changes in methodology and criteria and to reflect changes to the approved NERC Standard requirements.

1.1 REVISION HISTORY

Version	Date	Author	Supervisor	Comments
1.0	10/14/2011	Dawn Quick	Robert Fox	Initial document load into the DMS.
2.0	12/31/2012	Dawn Quick	Robert Fox	Annual Review. Seasonal Ratings defined. Internal Communication additions.
3.0	07/18/2013	Dawn Quick	Robert Fox	Add Generator Interconnection Section.
3.1	10/15/2013	Dawn Quick	Robert Fox	Add language for Single Breaker Ratings.
3.2	12/26/2013	Dawn Quick	Robert Fox	Annual Review. No Changes
3.3	03/10/2014	Dawn Quick	Ganesh Velummylum	Annual Review. Section 4.5. Added footnote pertaining to Distribution Factor. Added Specification of NERC categories and Cases to study.
4.0	10/07/2015	Dawn Quick	Lynn Schmidt	Annual Review. Format and Content Changes to align with new TPL Standard
4.1	01/10/2016	Dawn Quick	Lynn Schmidt	Annual Review.
4.2	01/10/2017	Dawn Quick	Lynn Schmidt	Annual Review.
4.3	01/10/2018	Dawn Quick	Lynn Schmidt	Annual Review. Change in document review/revision requirements.
4.4	03/09/2018	Dawn Quick	Lynn Schmidt	Addition of 765kV Voltage Criteria
4.5	05/29/2019	Dawn Quick	Lynn Schmidt	Addition of Energy Storage Interconnection Criteria
4.6	02/06/2020	Dawn Quick	Lynn Schmidt	Added P5 to Facility Connection Criteria
4.7	05/27/2020	Dawn Quick	Lynn Schmidt	GI Cumulative Impact criteria revision
4.8	01/14/2021	Dawn Quick	Lynn Schmidt	Addition of solar plant study criteria. Revision of wind machine voltage criteria

1.2 APPROVAL

Version	Supervisor	Title	Electronic Signature Date
1.0	Robert Fox	Leader Transmission Planning	9/28/2011
2.0	Robert Fox	Leader Transmission Planning	12/31/2012
3.0	Robert Fox	Leader Transmission Planning	7/18/2013
3.1	Robert Fox	Leader Transmission Planning	10/15/2013
3.2	Robert Fox	Leader Transmission Planning	12/26/2013
3.3	Ganesh Velummylum	Manager Electric System Planning	3/10/2014
4.0	Lynn Schmidt	Leader Transmission Planning	10/07/2015
4.1	Lynn Schmidt	Leader Transmission Planning	1/10/2016
4.2	Lynn Schmidt	Leader Transmission Planning	01/10/2017
4.3	Lynn Schmidt	Leader Transmission Planning	01/10/2018
4.4	Lynn Schmidt	Leader Transmission Planning	03/09/2018
4.5	Lynn Schmidt	Leader Transmission Planning	05/29/2019
4.6	Lynn Schmidt	Leader Transmission Planning	02/06/2020
4.7	Lynn Schmidt	Leader Transmission Planning	05/27/2020
4.8	Lynn Schmidt	Leader Transmission Planning	01/14/2021

2 ANNUAL PLANNING ASSESSMENT

Transmission Planning shall prepare an annual Planning Assessment of the performance of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated below), shall document assumptions, and shall document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. This assessment shall be performed for both the Near-Term and the Long-Term Transmission Planning Horizons. [R2]

Past studies may be used to support the Planning Assessment if they meet the following requirements:

- For steady state, short circuit, or stability analysis: the study shall be five calendar years old or less, unless a technical rationale is provided to demonstrate that the results of an older study are still valid. [R2.6.1]
- For steady state, short circuit, or stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included in the written assessment. [R2.6.2]

For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the required performance criteria, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the required performance criteria. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. [R2.7] [R2.8]

The Corrective Action Plan(s) shall:

- List System deficiencies and the associated actions needed to achieve required System performance. [R2.7.1] [R2.8.1]
- For Steady state and Stability Studies, include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary. [R2.7.2]
- Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures. [R2.7.4] [R2.8.2]

When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment. NIPSCO Transmission Planning shall evaluate its current stock and procurement strategy annually. Conclusions of this evaluation shall be stated in the assessment report. [R2.1.5]

In accordance with TPL-001-4 R7, NIPSCO has executed a Coordination Agreement with MISO identifying individual and joint responsibilities for performing the required studies. NIPSCO has not delegated any of their TPL responsibilities to MISO. In addition to any data requests made by MISO required to fulfill their TPL requirements, NIPSCO will also provide results from its Short Circuit studies to MISO. [R7]

Transmission Planning shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. Recipients of the Planning Assessment include: MISO, PJM, METC, Duke, and Ameren. [R8] [R8.1]

2.1 MODEL DATA

NIPSCO Transmission Planning shall maintain System models within the NIPSCO area for performing the studies needed to complete its Planning Assessment. The models are consistent with provisions of the most recent Multiregional Modeling Working Group Procedure Manual and the most recent MOD-32 standard, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. [R1].

System Models Represent:

- Existing Facilities
- Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. [R2.1.3]
- New planned Facilities and changes to existing Facilities
- Real and reactive Load forecasts
- Known commitments for Firm Transmission Service and Interchange
- Resources (supply or demand side) required for Load

A project is considered “planned” and is modeled in the base cases when a continuing need has been identified by recent and past study results. The planned project, in general, is needed in the near term and typically has budget approval for engineering or material costs.

A “proposed” project is typically not modeled in base cases. The “proposed” project is being studied for continuing need and timing when project lead time is sufficient. A “proposed” project may also be conceptual in nature. It has been identified as a possible solution in long term studies where violations may be marginal. It may also be identified as a possible solution to stressed or alternative dispatch cases. Alternative projects may be studied for best solution. Proposed projects are given a “planned” status after need has been proven, taking into consideration sufficient lead time.

2.2 *STEADY STATE*

In accordance with NERC Standard TPL-001-4, the following system conditions are required for study annually:

- System peak Load for either Year One or year two, and for year five. [R2.1.1]
- System Off-Peak Load for one of the five years [R2.1.2.]
- A current study assessing expected System Peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. [R2.2.1]

For each of the Near-Term studies described above, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment will vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response: [R2.1.4]

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.2.1 Contingency Analysis

For the steady state portion of the Planning Assessment, Transmission Planning shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons mentioned above. The studies shall be based on computer simulation models using data provided in accordance with TPL-001-4 Requirement R1. [R3]

A list of those Contingencies to be evaluated for System Performance for Planning Events shall be created corresponding to the Planning Events P0-P7 listed in Table 1. For steady state, all planning events are simulated unless contingency outages duplicate the same elements as those of another contingency. Results of these simulations should be assessed to determine whether the BES meets the performance requirements in section 2.2.2. [R3.1] [R3.4]

A list of Contingencies for those extreme events listed in Table 1 that are expected to produce more severe System impacts shall be identified and created. For Steady-State, all extreme events listed in Table 1, extreme events #1 and #2 shall be simulated. Wide-area events affecting the Transmission System, such as those described in Table 1, extreme events #3, may be evaluated. A description and rationale of these wide-area events, if included, will be documented in the assessment. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. [R3.2] [R3.5]

Transmission Planning shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. [R3.4.1]

Contingency analysis shall simulate the removal of all elements that the Protection System and other automatic controls that are expected to normally clear or disconnect for each Contingency without operator intervention. [R3.3.1]

The analyses shall include the impact of subsequent:

- Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Synchronous generator terminal voltages will be monitored at *85%* for potential tripping. Solar and Wind machine terminal voltages will be monitored at 90% for potential tripping. [R3.3.1.1]
- Tripping of Transmission elements where relay loadability limits are exceeded. A tripping proxy of 125% of Emergency Rating will be used for all lines and transformers. When exceeded, Transmission Planning will consult Protection Engineering to obtain actual trip values and determine if a corrective action plan is necessary. [R3.3.1.2]

Contingency analysis shall simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. [R3.3.2]

2.2.2 Steady-State Performance Requirements and Criteria [R5]

- Voltages, post-contingency voltages, and post-contingency voltage deviations shall be within acceptable limits. See Steady-State Voltage Tables below.
- Applicable Facility Ratings shall not be exceeded. Transmission Planning establishes Normal and Emergency Facility Ratings for summer and winter seasonal periods based on its documented Facility Rating Methodology. Single Breaker Ratings are also established for use in studies where the contingency may cause a facility to have a more limited rating.
- The transmission system shall not experience uncontrolled cascading or islanding. Load loss shall not exceed 300 MWs, excluding consequential load. See section 2.5, Supplemental Performance Analysis. [R6]
- Synchronous generators are projected to trip when the terminal voltage is below 85%. Solar and Wind machines are projected to trip when the terminal voltage is below 90%. [R3.3.1.1]
- Consequential Load Loss as well as generation loss is acceptable as a result of any event excluding category P0 No Contingency.
- The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady-state performance requirements.

<u>Steady-State Voltage Tables</u>

	Normal Condition		Post-Contingency Steady-State		
Location	Minimum	Maximum	Minimum	Maximum	Deviation
765 kV buses	92%	105%	90%	105%	+/- 10%
345 kV buses	92%	105%	90%	105%	+/- 10%
138 kV buses	92%	105%	90%	105%	+/- 10%
69 kV buses	94%	105%	92%	105%	+/- 10%
On-Line Synchronous Generator Terminals [3.3.1.1]	95%	105%	85%	107%	+/- 10%
On-Line Solar + Wind Machine Terminals [3.3.1.1]	95%	105%	90%	105%	+/- 10%

	Normal Condition		Post-Contingency Steady-State		
Location	Minimum	Maximum	Minimum	Maximum	Deviation
Customer Substation 138kV Buses	95%	105%	90%	110%	+/- 10%

2.3 *STABILITY*

In accordance with NERC Standard TPL-001-4, the following system conditions are required for study annually:

- System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. [R2.4.1]
- System Off-Peak Load for one of the five years. [R2.4.2]

For each of the studies described above, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: [R2.4.3.]

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability
- Generation additions, retirements, or other dispatch scenarios.

For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies and shall include documentation to support the technical rationale for determining material changes. [R2.5]

Loads shall be modeled by P (constant current) and Q (constant impedance) which represents the aggregate overall dynamic load behavior. For sensitivity analysis, loads may be modeled by a composite load model considering more detailed behavior of induction motor loads. [R2.4.1]

2.3.1 Contingency Events

For the Stability portion of the Planning Assessment, Transmission Planning shall perform the Contingency analyses for the Near-Term and Long-Term Planning Horizons mentioned above. The studies shall be based on computer simulation models using data provided in accordance with TPL-001-4 R1. [R4]

A list of those Contingencies to be evaluated for System Performance for Planning Events shall be created corresponding to the Planning Events P0-P7 listed in Table 1. For transient stability, Planning Events for transmission facilities directly associated to an individual power plant as well as Planning Events for other selected transmission facilities are simulated. [R4.4]

Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated for impact to the BES. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted. [R4.2] [R4.5]

Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. [R4.4.1]

Contingency analyses shall simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. [R4.3] [R4.3.1]

The contingency analyses shall include the impact of subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized. [R4.3.1.1]
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. [R4.3.1.2]
- Tripping of Transmission lines and transformers where transient swings will cause a Protection System operation based on generic or actual relay models. [R4.3.1.3]

Contingency analyses shall simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, synchronous condensers, static var compensators, power flow controllers, and DC Transmission controllers. [R4.3.2]

Studies shall be performed for planning events to determine whether the BES meets the following stability performance requirements and criteria: [R4.1] [R4.2]

2.3.2 Stability Performance Requirements and Criteria [R5]

The transmission system shall not experience uncontrolled cascading or islanding.

For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism. [R4.1.1]

For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. [R4.1.2]

For planning events P1 through P7: Power oscillations shall exhibit acceptable damping. Observed damping ratio (ζ) shall be greater than 0.020. [R4.1.3]

Synchronous Generator Voltage: Voltages at the terminal bus of on-line synchronous generators shall return to the allowable steady-state contingency voltage within five seconds after fault clearing. [R4.3.1.2]

Solar Generating Plant Voltage: Solar plants shall have low voltage ride-through capability monitored at the high-side GSU terminal down to 0% of the rated voltage for 0.150 seconds (9.0 cycles) for three-phase faults and down to 0% of the rated voltage for 0.433 seconds (26.0 cycles) for single-line ground faults. [R4.3.1.2]

Wind Generating Plant Voltage: Wind plants shall have low voltage ride-through capability monitored at the high-side GSU terminal down to 0% of the rated voltage for 0.150 seconds (9.0 cycles) for three-phase faults (Per FERC Order 661-A) and down to 0% of the rated voltage for 0.433 seconds (26.0 cycles) for single-line ground faults. [R4.3.1.2]

Load Bus Voltages: Voltages at load buses should return to the allowable steady-state contingency voltage within five seconds after fault clearing.

2.4 *Short Circuit*

The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and shall be supported by current or qualified past studies. The analysis shall be used to determine whether circuit breakers have the capability to interrupt the maximum short-circuit current the circuit breaker is expected to experience. [R2.3]

The System short-circuit model for the analysis shall be updated annually including planned generation and transmission facilities within NIPSCO, and including planned generation and transmission facilities in adjoining areas within two busses of NIPSCO.

The maximum expected short-circuit current that a circuit breaker is expected to interrupt shall be determined by performing both three-phase (3Ø) and single line-to-ground (SLG) fault simulations in accordance with the IEEE standard C37-010-1999 and utilizing the calculation methodology of the ASPEN Oneliner™ Breaker Rating Module. The circuit breaker interrupting rating shall be based on its nameplate value and not derated based on circuit breaker reclosing operations.

Circuit breakers with interrupting duty of 100% or greater of the interrupting rating shall be considered an identified deficiency.

2.5 *Supplemental Performance Analysis*

2.5.1 Cascading

Cascading potential shall be evaluated by sequentially removing those facilities with steady-state loading in excess of 125% of their emergency rating and those generating units with steady-state terminal voltage below their specified voltage criteria. [R6]

2.5.2 Uncontrolled Islanding

Uncontrolled islanding potential shall be evaluated by review of identified cascading outages that result in load being isolated with generation from the interconnected system. [R6]

2.5.3 Voltage Stability

Voltage stability analysis shall be performed for the Near-Term and Long-Term Planning Horizons mentioned above. Voltage stability shall be evaluated through the application of the Fast Voltage Stability Index (FVSI) and Voltage Stability Index Le. Analysis shall be performed for N-0 and N-1 contingency conditions. A voltage stability index value of 1.0 or greater is an indication of voltage instability. [R6]

3 FACILITY CONNECTION, TRANSMISSION SERVICE REQUEST ASSESSMENTS, AND GENERATOR RETIREMENTS

Transmission Reliability Planning Tests are performed on Facility Connection projects, Transmission Service Requests (TSR's), and Generation Retirements to evaluate any Thermal or Voltage criteria violations caused by projects originated through PJM, MISO and NIPSCO processes on NIPSCO's transmission system.

3.1 *INDIVIDUAL CONTRIBUTION TEST AND CUMULATIVE IMPACT TEST (CIT)*

The Facility Connection Projects, TSR's, and Generation Retirements impacting NIPSCO's transmission shall be subject to two tests: the Individual Contribution Test and the Cumulative Impact Test.

The Facility Connections, TSR's, and Generation Retirements screened through the following two tests are studied for their impact on NIPSCO's transmission system. The RTEP and MTEP cases used by PJM and/or MISO will be used in the study process. Peak, off-peak, and high wind cases should be evaluated to determine worst-case impact. Mitigations will be determined for all thermal and/or voltage violations evaluated under NERC Contingency Categories P0, P1, P2, P5 and P7.

Individual Contribution Test:

The test is performed to identify individual Facility Connections, TSRs, and Generation Retirements affecting NIPSCO's transmission system. For a Facility Connection, TSR, or Generation Retirement to be considered to be impacting the NIPSCO transmission system, it should adhere to one of the two rules:

1. The contribution of the Distribution Factor of the Facility Connection, TSR, or Generation Retirement with magnitude of 3% or greater contributing to an overload on a NIPSCO facility.

2. The Contribution of a Facility Connection, TSR, or Generation Retirement on a NIPSCO facility is equal to or greater than 3% of the facility rating.

Cumulative Impact Test (CIT):

NIPSCO shall also perform a test to evaluate the cumulative impact of multiple Facility Connections, TSRs, and Generation Retirements when they are grouped together in the same study during the PJM and/or MISO process. The Facility Connections, TSRs, and Generation Retirements having a cumulative impact of at least 10% of the facility rating will be considered as impacting NIPSCO's transmission system. There is no minimum threshold to assign individual impact.

3.2 *ENERGY STORAGE OR HYBRID FACILITY INTERCONNECTIONS*

The maximum expected charging load for any storage or hybrid facility interconnection to NIPSCO's transmission system will be studied as a non-interruptible load in both peak and off-peak conditions according to the most recent NERC TPL-001-4 standard methodology using the most recent NIPSCO transmission planning criteria.

TABLE 1. PLANNING AND EXTREME EVENTS

Category	Initial Condition	Event	Fault Type	Notes
P0	Normal System	None	N/A	Initial System Condition
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	3Ø	
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault	N/A	
		2. Bus Section Fault	SLG	
		3. Internal Breaker Fault (non-bus tie)	SLG	
		4. Internal Breaker Fault (Bus-tie Breaker)	SLG	
P3 Multiple Contingency	Loss of generator unit followed by System Adjustments	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	3Ø	
P4 Multiple Contingency (Fault plus Stuck Breaker)	Normal System	Loss of Multiple Elements Caused by a stuck Breaker (non-bus tie) attempting to clear a fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 5. Bus Section 6. Loss of Multiple elements caused by a stuck Bus-tie Breaker attempting to clear a fault on the associated bus.	SLG	

Category	**Initial Condition**	**Event**	**Fault Type**	**Notes**
P5	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 5. Bus section	SLG	
P6 Multiple Contingency	Loss of one of the following followed by System adjustments. Loss of one of the following: 1. Transmission Circuit 2. Transformer 3. Shunt Device	Loss of one of the following: 1. Transmission Circuit 2. Transformer 3. Shunt Device	3Ø	Curtailment of Firm Transmission Service is allowed as a System adjustment as identified in the column entitled 'Initial Condition'.
P7 Multiple Contingency	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure.	SLG	Excludes circuits that share a common structure for 1 mile or less.

Category	**Initial Condition**	**Event**	**Fault Type**	**Notes**
Extreme Event -Steady State 1	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	Steady State Only	
Extreme Event -Steady State 2	Normal	Local Area events affecting the Transmission System such as: a. Loss of a tower line with three or more circuits. b. Loss of all Transmission lines on a common Right-of-Way. c. Loss of a switching Station or Substation (loss of one voltage level plus transformers) d. Loss of all generating Units a generating Station e. Loss of a large Load or major Load Center	Steady State Only	
Extreme Event -Steady State 3	Normal System	Wide area events affecting the transmission System based on System Topology such as: a. Loss of two generating Stations. b. Other events based upon operating experience that may result in wide area disturbances.	Steady State Only	

Category	Initial Condition	Event	Fault Type	Notes
Extreme Event -Stability 1	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	3Ø fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	Stability Only -3Ø	
Extreme Event - Stability 2	Normal System	Local or wide area events affecting the Transmission System such as: a. 3Ø fault on generator with stuck breaker or a relay failure resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission Circuit with stuck breaker or a relay failure resulting in Delayed Fault Clearing. c. 3Ø fault on Transformer with stuck breaker or a relay failure resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker or a relay failure resulting in Delayed Fault Clearing. e. 3Ø internal breaker fault f. Other events based upon operating experience, such as consideration of initiating evens that experience suggests may result in wide area disturbances.		

Confidential Attachment 2-E (Redacted)

[Distribution Automation Program Business Case]

Confidential Attachment 2-F (Redacted)

[Long-Term Communications Plan]

Execution and Management of the Plan

Execution of the Plan

The Engineering and Asset Risk Management Departments developed the 2021-2026 Electric Plan as well as the cost estimates for the projects. The portfolio of projects included in the 2021-2026 Electric Plan are then assigned to the Scope Development & Estimating, Electric Projects, Project Management and Construction Department for execution and management. The TDSIC Project Controls Team has the primary role of verifying that TDSIC project costs are accurately forecasted and accounted for. This includes obtaining, validating, tracking and paying invoices for the portfolio of projects included in the 2021-2026 Electric Plan. The TDSIC Project Controls Team is also responsible for creating monthly forecasts and accruals with input from the Electric Projects and Construction Department.

Management of Projects

NIPSCO's internal stakeholders worked to develop the 2021-2026 Electric Plan as well as the cost estimates for the projects. The portfolio of projects included in the 2021-2026 Electric Plan are then assigned to the Scope Development & Estimating, Electric Projects, Project Management and Construction Department for execution and management. The TDSIC Project Controls Team has the primary role of verifying that TDSIC project costs are accurately forecasted and accounted for. This includes obtaining, validating, tracking and paying invoices for the portfolio of projects included in the 2021-

2026 Electric Plan. The TDSIC Project Controls Team is also responsible for creating monthly forecasts and accruals with input from the Electric Projects and Construction Department.

Management of Costs

The process for initiating a new TDSIC work order begins with the Project Engineer/Manager submitting a Capital Initiative Form ("CIF") to the TDSIC Support Budget Analyst. The Budget Analyst routes the CIF to the Plan Owner and the Project Execution Team for two levels of approval. The purpose of the first level of approval, termed "TDSIC Verification," is to verify that the project and costs are TDSIC eligible. This ensures that only eligible project costs are tracked via the TDSIC tracker. The Plan Owner approves projects for TDSIC eligibility by referring to NIPSCO's currently approved 2021-2026 Electric Plan. The Plan Owner is responsible for understanding the intent and purpose of the overall Plan, and reviews all requests to determine if the work is approved within the Plan. The Plan Owner also reviews new project requests to be included in the next Plan update and determines it the project is an eligible improvement and necessary for purposes of system reliability and Grid Modernization. This is a critical piece of the TDSIC Plan as it is allows the most flexibility for the utility as the system continues to change.

The purpose of the second level of approval, termed "Work Order Approval," is to authorize the project work. The work order is approved by the Project Execution Leaders depending on the dollar amount of the request. Both TDSIC Verification and Work Order Approval are required before work is performed and project costs are incurred. The only exception to this process is when a work order is needed for an emergency, where approvals are obtained after the work order is provided to the Project Engineer/Manager. If the work order is determined not to be an eligible TDSIC project after it was routed through for formal approval, the work order is cancelled and removed from the TDSIC work order list. The emergency work order process is not a common occurrence, but may occasionally happen.

At the time of request and during the review and approval process, TDSIC work orders are identified and classified by category and sub-category. Once approved, the TDSIC Budget Analyst flags the TDSIC work order in NIPSCO's Fixed Asset System (PowerPlant) with the specific TDSIC category and sub-category. These identifiers and classifications in PowerPlant assist in ensuring that only TDSIC work orders are included for recovery.

Once a TDSIC work order is initiated, NIPSCO records charges to the work order in accordance with the internal controls discussed below. Capital dollars at NIPSCO are separated into two segments: (1) direct capital and (2) indirect capital. Direct capital represents costs such as the materials and equipment installed and the labor costs of the workers performing the construction. Typically, these are costs that are incurred at the job site. Indirect costs are associated with capital projects and must be capitalized in order to comply with GAAP. However, these often cannot be charged directly to a specific capital project work order as they cannot be directly linked to one particular project. These capital costs tend to be incurred away from the job site. NIPSCO groups these indirect capital costs into three categories: (1) overheads, (2) stores, freight and handling, and (3) AFUDC. Vendor related direct costs are procured through the use of a Material Requisition ("MR"). A purchase order ("PO") is required to order goods or services. To initiate a PO with a vendor, an MR is initiated and routed for approval. The MRs related to TDSIC projects are labeled with a specific route code to ensure they are first routed to the TDSIC Project Controls Team, who then routes the request for required approvals. The MRs are approved by the Project Execution Leaders depending upon the dollar amount of the request. The Procurement group then generates a PO, which is identified as a TDSIC PO. This TDSIC route code on the PO ensures that TDSIC invoices are routed to the TDSIC Project Controls Team for validation. The TDSIC Project Controls Team routes TDSIC invoices to the TDSIC Project Execution group for two levels of approval.

In addition to the controls discussed above, the TDSIC Project Controls Team provides to the TDSIC Project Managers reports weekly that show the actual project costs recorded to each work order. The TDSIC Project Controls Cost Engineers meet monthly one-on-one with the TDSIC Project Managers to review actual costs, to estimate accruals, and to forecast the project costs. TDSIC Project Managers also review all project costs to ensure that costs are properly recorded to the TDSIC work orders. This process includes the review of non-vendor payments such as internal labor and other direct costs. The TDSIC Project Manager reviews the detailed project cost reports provided by the TDSIC Project Controls Team to ensure that all vendor payments are properly recorded, and internal labor charges are appropriate. Any unusual charges are investigated and corrected if necessary.

Project Management Principles

NIPSCO's Project Managers have been trained and most have been certified as Project Management Professionals ("PMPs") and follow the Project Management Institute ("PMI") Project Management Body of Knowledge ("PMBOK") principles. The project life cycle is a core concern of NIPSCO's senior leadership, as well as the rest of the organization, and the status of each project is reviewed on a monthly basis. As discussed above, a TDSIC Project Controls Team is in place to ensure that items such as cost, scope, schedule and safety are being properly managed.

Inclusion of Contingency in Cost Estimates

Contingency is an amount added to a project base cost estimate to cover uncertainty and project risk. Incorporation of contingency is critical to creating a realistic estimate of the final project cost and increases the transparency around the expected cost at completion for a project. Projects are developed through a process of progressive elaboration whereby details to complete the scope required to satisfy the project deliverables are developed through an iterative process over time. Projects are generally not fully engineered or bid at the time the cost estimates are developed. To expend the resources required to eliminate uncertainty during early stages of project development would not be cost effective or reasonable.

Contingency is added for several reasons, including but not limited to: (1) covering details that may be identified later in the iterative design process; (2) covering requirements that may not have been reasonably anticipated during the land acquisition or permitting process; (3) addressing responses or exceptions that may not have been reasonably anticipated during the bid process; (4) changes in system configuration or operational constraints; or (5) accounting for field conditions where it is neither possible nor reasonable to identify all construction risks that could be encountered. It is important to note that a contingency may not cover all unanticipated costs. The AACE recognizes use of contingency to mitigate unexpected, additional costs as industry best practices. Without the inclusion of contingency, project estimates would not be "best estimates" as required by the TDSIC Statute. Once NIPSCO successfully completes various stages of a project, the contingency amount is updated.

Maintaining an appropriate contingency can actually prevent project cost increases by providing a process that avoids costly project interruptions or delays when an issue or risk is realized. The contingency is added to cover estimate uncertainty and risk. Contingency increases transparency for the project stakeholders and provides the Project Manager with an appropriate tool to manage issues or risks that may be realized during project development or execution. It also provides the Project Manager with resources to avoid detrimental trade-offs in schedule, scope, quality, or functionality. Ultimately, an appropriate contingency increases the confidence in completing the project within the estimated cost.

Contingency is a way of accounting for known or potential risks associated with a project, and is not inclusive of every risk that could impact the cost of completion. For example, with construction in northwest Indiana, dewatering can become a significant part of the project expense due to the high ground water table. The estimates provide for normal or reasonably anticipated dewatering costs. The contingency is assigned to at least partially cover unusual conditions where extensive dewatering is required. However, it is not intended to fully cover dewatering from conditions that are historically atypical, such as record levels of precipitation during a particular construction season.

For projects planned for execution further out in the Plan, another risk that is not covered by contingency is the potential for significant changes in costs on materials since material fluctuations can be affected by unforeseen circumstances, as evidenced by recent circumstances related to lumber and other raw materials increasing dramatically. The demand for labor could also increase costs more than the amount that was included in the current estimates.