FILED
April 21, 2023
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61, AND, 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RETAIL RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS (BOTH EXISTING AND NEW); (3) APPROVAL OF A NEW RIDER FOR VARIABLE NON-LABOR O&M EXPENSES ASSOCIATED WITH COAL-FIRED GENERATION; (4) MODIFICATION OF THE FUEL COST ADJUSTMENT TO PASS BACK 100% OF OFF-SYSTEM SALES REVENUES NET OF EXPENSES; (5) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (6) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING BUT NOT LIMITED TO APPROVAL OF (A) CERTAIN DEFERRAL MECHANISMS FOR PENSION AND OTHER POST-RETIREMENT BENEFITS EXPENSES; (B) APPROVAL OF REGULATORY ACCOUNTING FOR ACTUAL COSTS OF REMOVAL ASSOCIATED WITH COAL UNITS FOLLOWING THE RETIREMENT OF MICHIGAN CITY UNIT 12, AND (C) A MODIFICATION OF JOINT VENTURE ACCOUNTING AUTHORITY TO COMBINE RESERVE ACCOUNTS FOR PURPOSES OF PASSING BACK JOINT VENTURE CASH, (7) APPROVAL OF ALTERNATIVE REGULATORY PLANS FOR THE (A) MODIFICATION OF ITS INDUSTRIAL SERVICE STRUCTURE, AND (B) IMPLEMENTATION OF A LOW INCOME PROGRAM; AND (8) REVIEW AND DETERMINATION OF NIPSCO'S EARNINGS BANK FOR PURPOSES OF IND. CODE § 8-1-2-42.3.	)	**CAUSE NO. 45772**

PETITIONER'S SUBMISSION OF SECOND SET OF CORRECTIONS

Northern Indiana Public Service Company LLC ("NIPSCO"), by counsel, respectfully submits the attached corrections to its prepared case-in-chief as listed below:

Direct Testimony of Erin E. Whitehead (Petitioner's Exhibit No. 2)
Revised Pages 95, 96, 97, 98, and 99 to correct the number reference of certain riders that were inadvertently carried over from the testimony in NIPSCO's last rate case. A clean and redlined version of the corrections is attached.
Direct Testimony of Ronald Talbot (Petitioner's Exhibit No. 9)
Revised all pages to correct the header. A clean and redlined version of the corrections is attached.

The clean versions of the corrections will be included in the court reporter's copies offered into evidence at the hearing.

Respectfully submitted,

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Dated this 21st day of April, 2023.

Bryan M. Likins

Rider 578 – Purchases From Cogeneration and Small Power Production Facilities (COG)

Rider 578 is available to a Qualifying Facility, as defined in the Rules. A contract is required between the Company and each Qualifying Facility, setting forth all terms and conditions governing the purchase of electric power. Rider 578 continues substantially unchanged.

Rider 579 – Interconnection Standards (IS)

Rider 579 is provided in accordance with the applicable standards, rules and regulations of the Commission's Rules as specified in the Indiana Administrative Code. Rider 579 continues substantially unchanged.

Rider 580 – Net Metering (NM)

Rider 580 is provided in compliance with Indiana Code § 8-1-40-10 and applicable Commission Rules. NIPSCO has added a provision to meet requirements of the statute.

Rider 581 – Demand Response Resource Type 1 (DRR-1) – Energy Only (DRR 1)

Rider 581 is available to Customers taking service under Rates 523, 524, 525, 526, 531, 532, and 533 who have sustained ability to reduce energy requirements through indirect participation in the MISO wholesale energy

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market by managing electric usage as described by MISO. This Rider is available to any load that is participating in Rate 531 and registered as a Load Modifying Resource; unless MISO rules change and do not permit load used by the Company as a Load Modifying Resource to also participate as a Demand Response Resource; provided, however, load may not participate as a Demand Response Resource if such participation would be inconsistent with the provisions of Rates 531, 532, or 533. The Customer shall enter into a written contract with the Company to reduce a portion of its electric load for single or multiple Interval Data Recorder meters through participation with the Company acting as the Market Participant for the Customer. Customer shall be either an Asset Owner (AO), Non-Asset Owner (NAO), or Aggregator of Retail Customers (ARC). Changes were made to better align with proposed Rates 531, 532, and 533. NIPSCO also has removed the Marginal Forgone Retail Rate ("MFRR") provisions within the Rider to better align with MISO's treatment of demand response resources and to reduce potential barriers to customer participation. This is further discussed by NIPSCO Witness Campbell.

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Rider 582 – Emergency Demand Response Resource (EDR) – Energy Only (EDR-1)

Rider 582 is available to Customers taking service under Rates 523, 524, 525, 526, 531, 532, or 533 who have a sustained ability to reduce energy requirements through indirect participation in MISO wholesale energy market by managing electric usage as described by MISO. This Rider is available to any load that is participating in Rate 531 and registered as a Load Modifying Resource, unless MISO rules change and do not permit load used by the Company as a Load Modifying Resource to also participate as an Emergency Demand Response Resource; provided, however, load may not participate as a Demand Response Resource if such participation would be inconsistent with the provisions of Rates 531, 532, or 533. The Customer shall enter into a written contract with the Company to reduce a portion of its electric load for single or multiple Interval Data Recorder meters through participation with the Company acting as the Market Participant for the Customer. Customers who do not qualify as a Load Modifying Resource may, however, participate as an EDR with any load. Customers taking service under this Rider shall not take power under the temporary, surplus power, back-up and maintenance services during an event under this Rider. Customer shall be either an Asset Owner (AO), Non-Asset Owner (NAO), or Aggregator of Retail Customers (ARC).

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Rider 583 – Adjustment of Charges for Demand-Side Management Adjustment Mechanism (DSMA)

Rider 583 is an annual mechanism to recover costs, including lost revenue and financial incentives, applicable to Demand Side Management ("DSM") programs. Rider 583 was updated to remove information relating to prior year Opt Outs (2014) that were no longer required. The DSMA Factors are shown in Appendix G. Rider 583 continues substantially unchanged.

Rider 586 – Green Power Rider (GPR)

Rider 586 provides Customers with the option to designate a specific percentage of their energy consumption as associated with Green Power. Customers pay a surcharge for energy consumption associated with Green Power. The Green Power Rider Rates are shown in Appendix H. NIPSCO has added clarification language related to requests to withdraw. Rider 586 continues substantially unchanged.

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Rider 587 – Adjustment of Charges for Federally Mandated Costs (FMCA)

Rider 587 is a semi-annual mechanism to recover federally mandated costs associated with a Commission-approved Certificate of Public Convenience and Necessity (CPCN) pursuant to Ind. Code § 8-1-8.4 *et al*. and incurred in connection with approved federally mandated compliance projects. The production and energy allocators utilized for purposes of allocating the costs inside of this Rider will be updated based upon the Allocated Cost of Service Study. The FMCA Factors are shown in Appendix I. Rider 587 continues substantially unchanged.

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Rider 588 – Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge (TDSIC)

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Rider 589 – Excess Distributed Generation

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<u>Rider 589 – Excess Distributed Generation</u>

VERIFIED DIRECT TESTIMONY OF RONALD E. TALBOT

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

A1. My name is Ronald E. Talbot. My business address is 801 East 86th Avenue, Merrillville, Indiana 46410. I am the Senior Vice President, Electric Operations for Northern Indiana Public Service Company LLC ("NIPSCO").

Q2. Please briefly describe your educational and business experience.

A2. I have served as the Senior Vice President of Electric Operations responsible for leading the organization's power delivery, electric generation, and transmission functions since April 2020. I have more than 30 years of experience of strategic problem solving and process improvement in the utility industry and have held a number of senior officer roles spanning operations, safety, IT and supply chain, as well as consulting. I served as the senior vice president and Chief Operating Officer ("COO") of PNM Resources until February 2017, where I was responsible for all vertically integrated utility operations for Public Service New Mexico, and I was also responsible for overseeing Texas New Mexico Power. I was appointed

COO of Indianapolis Power and Light ("IPL") (now AES Indiana) in June of 2011. Prior to serving as COO, I served as Senior Vice President Power Supply beginning in March of 2007, and was responsible for IPL's generating stations, fuel procurement, generation dispatch, and wholesale trading. I joined IPL as Senior Vice President of Customer Operations in August 2003. Previously, I was Vice President of Chicago Region Operations for Commonwealth Edison Company in Chicago from December 1999 to April 2002. Prior to that, I worked for approximately 15 years in various capacities for Consolidated Edison in New York, including General Manager of Staten Island Electric Operations and later General Manager of Manhattan Electric Operations. I have baccalaureate degrees in economics from SUNY Oneonta and in electrical engineering from Clarkson University, as well as a Master of Science in Electrical Engineering from the New Jersey Institute of Technology. Over the course of my career, I have also served on numerous industry and not for profit boards of directors.

Q3. What are your current responsibilities as Senior Vice President, Electric Operations of NIPSCO?

A3. As Senior Vice President, Electric Operations, I am responsible for all aspects of NIPSCO's electric operations, including NIPSCO's electric transmission and distribution system, as well as NIPSCO's generating assets.

Q4. Have you previously testified before the Indiana Utility Regulatory Commission ("Commission") or any other regulatory commission?

A4. Yes. I filed testimony before the Commission in Cause No. 38706-FAC-130-S1. I have also made several presentations before the Commission and staff, as well as before New Mexico Public Regulation Commission.

Q5. Are you sponsoring any attachments to your testimony in this Cause?

A5. No.

Q6. What is the purpose of your testimony?

A6. The purpose of my testimony is to: (1) describe NIPSCO's generation fleet; (2) describe NIPSCO's electric transmission and distribution systems; (3) discuss the Company's customer service and electric reliability programs; (4) describe the significant investments NIPSCO has made to its generation and transmission and distribution systems in recent years; and (5) explain various pro-forma expense adjustments.

Q7. Has NIPSCO made significant investments in its electric facilities that is driving the relief sought in this case?

A7. Yes. Approximately three years have passed since the test year used to establish NIPSCO's current rates. During that time period, NIPSCO has invested significantly in its infrastructure related to its jurisdictional electric operations, and this is expected to continue through the end of the Forward Test Year (December 31, 2023) for this proceeding. NIPSCO's generation transition and modernization of its transmission and distribution systems have driven the overwhelming majority of these investments.

<u>**NIPSCO's Generation Fleet**</u>

Q8. Are you familiar with NIPSCO's generating facilities?

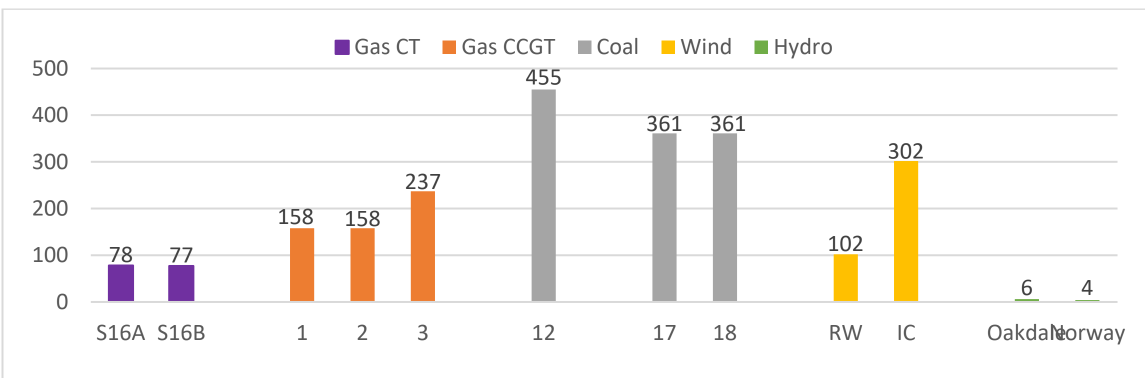
A8. Yes.

Q9. Please generally describe NIPSCO's generation fleet.

A9. The NIPSCO generating facilities have a total installed capacity of 2,299 net megawatts ("MW") and consist of seven (7) separate generation sites, including the R.M. Schahfer Generating Station ("Schahfer" or "RMSGS") (Units 16A, 16B, 17 and 18), Michigan City Generating Station ("Michigan

City" or "MCGS") (Unit 12), Sugar Creek Generating Station ("Sugar Creek" or "SCGS") (SC1, SC2, and SS1), Rosewater Wind Farm ("Rosewater"), and Indiana Crossroads I Wind Farm ("Crossroads Wind I") and two (2) hydroelectric generating sites (Oakdale and Norway). Of the total capacity, 51.20% is from coal-fired units, 30.80% is from natural gas-fired units, 17.57% is from renewables (wind), and 0.43% is from hydroelectric units. Figure 1 illustrates the installed net capacity and unit identification of NIPSCO's generating units.

Figure 1. Installed net capacity of generating units (MW)



Q10. What changes has NIPSCO made to its generation fleet since its last electric rate case in Cause No. 45159 ("45159 Electric Rate Case")?

A10. Since the 45159 Electric Rate Case, NIPSCO (a) retired Unit 10 at Bailly Generating Station (as of July 15, 2020) and Units 14 and 15 at Schahfer (as of October 2021), and (b) added Rosewater (as of December 2020) and Crossroads Wind I (as of December 2021).

Q11. Have there been other planned changes to NIPSCO's generation fleet since the 45159 Electric Rate Case?

A11. Yes. Following NIPSCO's 2018 Integrated Resource Plan ("IRP") and coming out of the 45159 Electric Rate Case, NIPSCO expected that Schahfer Units 17 and 18 would retire no later than May 31, 2023, which was contingent upon the development and completion of the remaining portfolio of renewable projects to replace the energy and capacity of the units. However, based on delays to NIPSCO's planned renewable generation projects, which is further discussed by NIPSCO Witness Campbell, NIPSCO announced in May of 2022 that Units 17 and 18 would continue to operate beyond May of 2023 and would retire by the end of 2025. NIPSCO Witness Augustine explains the evaluation NIPSCO undertook that led to this decision, but, in short, the decision was made to ensure NIPSCO could reliably and adequately serve its customers as it continues execution of its generation transition.

Q12. What was the driver of NIPSCO's decision to extend operation of Units 17 and 18?

A12. Throughout NIPSCO's generation transition, providing reliable service to its customers has been top-of-mind. Based on various market factors beyond NIPSCO's control, which are discussed by NIPSCO Witness Campbell, it became apparent that some of NIPSCO's solar and solar plus storage projects originally anticipated to come online in 2023 would be delayed. This led NIPSCO to evaluate the best path forward under these uncertain circumstances. There were two primary alternatives NIPSCO evaluated. First, NIPSCO could continue with the planned retirement of Units 17 and 18 by May 31, 2023 and look to fill the capacity need associated with delayed renewable projects with other resources—which would have primarily been bilateral agreements. Second, NIPSCO could delay the retirement of Unit 17 and 18 and use these existing generation resources through 2025. Ultimately, NIPSCO determined utilizing these existing baseload, dispatchable resources to serve customers was the best decision to ensure NIPSCO continues to provide reliable and adequate service to its customers and meet reliability obligations to the Midcontinent Independent System Operator, Inc. ("MISO"). NIPSCO Witness Augustine discusses additional economic analysis performed in 2022 at NIPSCO's direction that supports this decision as well.

Q13. What investments has NIPSCO made to its generation fleet since the 45159 Electric Rate Case?

A13. Since the 45159 Electric Rate Case, NIPSCO has made significant investments in its transition to renewable generation. As noted above, Rosewater and Crossroads Wind I are both now in-service. There are two additional renewable generation projects forecasted to be online in 2023: (1) Indiana Crossroads Solar Park ("Crossroads Solar") and (2) Dunn's Bridge I Solar Park ("Dunn's Bridge I"). Significant capital investments to the NIPSCO generation fleet that were placed in-service since the 45159 Electric Rate Case (or forecasted to be in-service by the end of the Forward Test Year (December 31, 2023)), including the investments in NIPSCO's transition to renewable generation, are shown in Table 1 below:

Table 1

Facility	Description	Direct Capital (in millions)
2020 In Service		
MCGS	Seawall Upgrades	$2.14
Oakdale	#2 Generator and Turbine Overhaul	$1.21

Facility	Description	Direct Capital (in millions)
R.W.	Rosewater 102MW Wind Farm	$89.90
RMSGS	Unit 18 Turbine Valve Replacements	$1.05
2021 In Service		
I.C.W.	Indiana Crossroads 302MW Wind Farm	$302.58
MCGS	Coal Car Dumper Feeder and Chute Replacement	$3.11
MCGS	Coal Car Thaw Shed Heater Replacements	$1.10
MCGS	Unit 12 Cooling Tower Fill, Drift Eliminator, and Louver Replace	$1.41
MCGS	SCR Catalyst Layer 4 Replacement	$1.20
MCGS	North ID Fan Rotor Replacement	$1.00
Oakdale	Concrete Rehabilitation	$2.42
RMSGS	Leachate Pipeline Project to Waste Water Treatment Facility	$1.11
RMSGS	Stalbaum Ditch Drainage Improvement Project	$1.19
SCGS	Boiler Feed Pump Replacements	$4.61
2022 In Service / Forecast		
MCGS	SCR Catalyst Layer 1 Replacement	$1.39
Norway	Control System Upgrade	$1.50
Oakdale	Control System Upgrade	$1.50
Oakdale	Oakdale Flood Gate and Stop Log Replacements	$4.24
RMSGS	Unit 16A Turbine Major Overhaul	$5.87
2023 Forecast		
D.B.	Dunn's Bridge I 265MW Solar	$233.74
I.C.S.	Indiana Crossroads 200 MW Solar	$191.07
MCGS	High Energy Valve Replacements (240/260)	$1.00
MCGS	FGD Reactor Upgrade	$1.00
MCGS	Unit 12 Controls Upgrade	$1.70
MCGS	Unit 12 Water Cannons Upgrade	$1.02
Norway	Norway Flood Gate Replacements	$4.00
Oakdale	Oakdale Head Gate and Stop Log Replacements	$6.91
Oakdale	Scrollcase Rehabilitation	$1.73
Oakdale	Transformer and Substation Relocation	$1.44
SCGS	Advanced Gas Path Upgrade	$20.7
SCGS	GT1 Flared 7A Enhanced Compressor Upgrade	$6.05
SCGS	Spare Generator Step Up Transformer	$3.04
SCGS	LTSA Hot Gat Path Inspection and Repairs	$14.08

Q14. Please describe improvements made at Sugar Creek and how those improvements will impact customers.

A14. In the fourth quarter of 2023, Sugar Creek will have completed two large projects with benefits to customers beginning in November 2023. First, an Advanced Gas Path Upgrade will replace key components within the gas turbines to increase overall facility capacity by 40 to 46 MW depending on ambient operating conditions. These modifications will allow for greater unit dispatchable output as well as improved heat rate. There are increased maintenance costs associated with this upgrade, but the expected net present value of the project overall is approximately $10.5 million. Second, the GT1 Flared 7A Enhanced Compressor Upgrade is replacement of original components in the gas turbine compressor sections with upgraded components providing for longevity and reliability. These upgrades, directly address capacity concerns in addition to setting Sugar Creek on a path to sustained high capacity factor and availability, while maintaining a low Effective Forced Outage Rate.

Q15. Does NIPSCO regularly report to the Commission and stakeholders on key reliability metrics?

A15. Yes. Coming out of Cause No. 44688, which is the NIPSCO electric rate case preceding the 45159 Electric Rate Case, NIPSCO was required to file an annual Performance Metrics Collaborative ("PMC") Report. This Report includes sections on Safety, Reliability, Customer Service, Investment & Spending, and other items. I discuss some of these topics below, but NIPSCO's most recent PMC Report was filed with the Commission in Cause No. 44688 on July 1, 2022.

Base Cost of Fuel and Coal Inventory Levels

Q16. What was NIPSCO's level of fuel expense in the Historic Base Period?

A16. The adjusted retail jurisdictional cost of fuel in the Historic Base Period reported in Petitioner's Exhibit No. 3, Attachment 3-B-S2, FPP Module was $416,398,339 (Line 1, Column A).

Q17. Were NIPSCO's retail jurisdictional fuel costs during the Historic Base Period reasonable?

A17. Yes. NIPSCO made (and continues to make) every reasonable effort to acquire fuel to provide electricity to its retail customers at the lowest fuel cost reasonably possible. As NIPSCO regularly explains in its quarterly fuel adjustment clause proceedings, NIPSCO purchases fuel (coal) pursuant to long-term contracts entered into using competitive bidding and on the spot markets. For gas-fired generators (combustion turbines and Sugar Creek), NIPSCO purchases natural gas pursuant to supply contracts that are entered into using a competitive bidding process. Historically, the natural gas supply contracts have been seasonal or annual in duration, ensure firm delivery of natural gas to the generator, and have competitive pricing options based upon prevailing market conditions. NIPSCO considers several factors in making fuel procurement decisions, including price, quality, suitability, environmental attributes, transportation costs and logistics, supplier availability, reliability, and diversity. Market factors also affect fuel purchases.

Q18. What was the coal inventory level in the Historic Base Period?

A18. The retail jurisdictional coal inventory level reported in Petitioner's Exhibit No. 3, Attachment 3-B-S2, RB Module for the Historic Base Period was $32,190,387 (Line 13, Column A)

Q19. Is this coal inventory level reasonable?

A19. Yes. This coal inventory level is consistent with NIPSCO's fuel inventory strategy, which was provided as part of the Minimum Standard Filing

Requirements. NIPSCO's fuel inventory strategy is designed to balance the costs associated with maintaining coal inventory with reliability to ensure units are available to supply energy during periods of high demand, extreme weather, or fuel transportation disruptions or mine production problems.

Q20. You mentioned above that NIPSCO now plans to retire Schahfer Units 17 and 18 no later than December 31, 2025, as opposed to no later than May 31, 2023. Has NIPSCO procured sufficient coal associated with this extension?

A20. Yes. Since announcing the change in expected retirement date for Units 17 and 18, NIPSCO was able to procure the coal necessary to continue operations through 2025. Specifically, NIPSCO has entered into a term Illinois Basin coal supply agreement with Peabody Coal Sales, LLC to cover a significant portion of anticipated coal supply requirements for the extension period.

NIPSCO's Safety Culture

Q21. Please describe NIPSCO's safety culture.

A21. NIPSCO's safety culture has continued to make progress over the years. In 2021, NIPSCO continued work on its Safety Management System ("SMS") by expanding the program into its Electric Operations. These efforts are making progress with NIPSCO's safety culture by addressing issues related to safety, through the SMS program, which is based on the American Petroleum Institute (API) Recommended Practice (RP) 1173. SMS is anchored by Core Four (4) Responsibilities which include, (1) Following Our Processes and Procedures; (2) Identifying and Reporting Risks; (3) Continually Improving Processes and Procedures; and (4) Identifying and Proactively Taking Action.

NIPSCO's SMS journey is intended to take safety to a new level of continuous improvement. It brings together people, processes, and culture to proactively find and act on risks to employees, contractors, customers, and communities. SMS drives learning from past experiences, enhanced risk models and input from teams on the front lines. These lessons drive improvements that protect customers and communities, along with employees and contractors. The Corrective Action Program ("CAP") is a foundational part of that effort. The Corrective Action Program offers a simple way to document identified risks and a systematic process to review, prioritize, address, and track progress to reduce them. Submitting an issue, concern, or risk in the Corrective Action Program starts a rigorous process that can lead to resolving a prioritized risk through corrective action.

To continue building a stronger safety culture, starting in 2021, NIPSCO began developing written programs for certain types of work that are considered High Consequence Tasks—critical operational processes that, if not performed properly, have the possibility of leading to a high consequence outcome and putting NIPSCO's teams, customers, and communities at risk. This 2021 initiative paid special attention to those riskiest tasks by developing guidelines to document critical operations and safety protocols. Employees and contractors review these guidelines before performing the work to be certain the processes and standards that apply are fresh in their minds. Employee feedback was incorporated into the design, providing a simple way to consistently navigate through the critical steps of High Consequence Tasks.

Q22. Have NIPSCO's safety metrics improved in recent years?

A22. Yes. As shown in Table 2 below, overall, NIPSCO has made a 34% improvement in the OSHA recordable injury rate, held steady in DART (days away, restriction or transfer) injury rate, and recorded a 10% improvement in PVC (preventative vehicle crash) incidents from year end 2012 to year end 2021. As shown in Table 3 below, in Electric Operations, NIPSCO has seen a 27% improvement in its OSHA recordable injury rate, a 9% downturn in DART (days away, restriction or transfer) injury rate, and a 46% improvement in PVC incidents from year end 2012 to year end 2021.

The recent downward trend in DART is due to COVID cases, medical case management by providers, and soft tissue injuries. COVID cases that are deemed work-related for recordability will tend to always follow in DART classifications and NIPSCO continues to monitor CDC guidance for strategies to implement to prevent and/or reduce workplace transmission of COVID. Additionally, medical providers are essentially changing to more conservative treatment methods and as a result, NIPSCO has noticed a rise in DART cases in recent years. NIPSCO continues to work with the NiSource Medical Director in obtaining access to the best available occupational health clinics in providing treatment to our employees. In certain instances, clinics have been replaced to better align with our vision and quality of care. Additionally, where soft tissue injuries have resulted in DART cases, the organization has recently implemented a new program called NIPSCO Moves that incorporates the latest advances in science for injury prevention utilizing the same techniques and principles incorporated by USA Olympic and professional athletes. The combined impact of these three areas on NIPSCO's DART rates should improve in coming years as our strategies for prevention and reduction are underway.

Table 2

NIPSCO Overall Performance ^^			
Year	OSHA Rate	DART Rate	PVC Incidents
2012	1.83	1.04	51
2013	1.50	0.93	45
2014	1.26	0.84	40
2015	1.23	0.65	47
2016	1.20	0.61	34
2017	0.75	0.33	38
2018	1.14	0.68	42
2019	1.33	0.88	57
2020	1.24	0.75	36
2021	1.20	1.04	46
^^ Includes all NIPSCO operations			

Table 3

NIPSCO Electric Stats			
Year	OSHA Rate	DART Rate	PVC Incidents
2012	2.46	1.54	26
2013	1.44	0.99	16
2014	1.41	0.97	20
2015	2.20	1.18	21
2016	2.23	1.37	13
2017	1.30	0.61	11
2018	2.23	1.61	21
2019	2.70	1.95	21
2020	2.61	1.59	13
2021	1.79	1.69	14

Q23. Does NIPSCO's focus on safety benefit customers?

A23. Yes. NIPSCO's focus on safety helps customers in a variety of ways. This focus ensures a healthier, more productive workforce while keeping the public as safe as possible. By keeping employees safer, NIPSCO is lowering costs for overtime or contracted work to replace an injured work force. NIPSCO is reducing hidden costs by preventing tired or less experienced employees from having to replace more experienced employees when they are injured. All other factors remaining constant, focusing on safety reduces NIPSCO's operating costs.

From a public safety and reliability standpoint, NIPSCO is using a risk-based prioritization approach as a guide in long-term system modernization planning. This approach identifies the highest-risk assets within the NIPSCO electric system and focuses mitigation planning on assets with the highest risk of failure. All major electric transmission and distribution assets, such as substation transformers, substation breakers and circuits, are included in this modeling approach. The scores derived from this risk model provide focus to high-risk assets and assist in prioritizing other areas of the business such as inspections, maintenance, load growth, and grid modernization. This approach helps keep NIPSCO's electric assets performing as anticipated and reducing overall risk of failure with a release of energy in public areas.

Additionally, NIPSCO is committed to educating the public about the importance of safe digging by promoting local 811 programs – the national, universal phone number and free service to call ahead of any digging project to have underground utilities marked. The number one cause of natural gas pipeline and underground electric primary damage is from third parties digging near underground facilities. NIPSCO focuses on educating the public about the importance of calling 811. Realizing its employees are NIPSCO's best advocates and connection to its customers and the communities we serve, NIPSCO added 811 logos to its company uniforms. National Safe Digging Month (April) and National Safe Digging Day (August 11) give NIPSCO opportunities to recognize and celebrate local partners in safe digging.

NIPSCO's Electric Transmission and Distribution Systems

Q24. Please describe NIPSCO's electric transmission system.

A24. 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 1,682 circuit miles of 69 kV transmission lines. In addition, NIPSCO has 66 transmission substations. NIPSCO is interconnected with seven neighboring utilities. The Company has transmission interconnects with American Electric Power or its affiliates, at the 345 kV, 138 kV, and 69 kV operating voltages. NIPSCO also interconnects with Commonwealth Edison at 345 kV and 138 kV and with Duke Energy Indiana at 345 kV, 138 kV and 69 kV and with NextEra Energy Transmission at 345 kV. NIPSCO has a single 138 kV interconnection with both Ameren and International

Transmission Company and a single 765 kV interconnection with Pioneer Transmission.

Q25. Please provide an overview of the NIPSCO electric distribution system.

A25. NIPSCO serves more than 483,000 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, and radiate from approximately 249 distribution substations. There are approximately 8,246 miles of overhead line with about 2,643 miles of underground cable.

Transmission and Distribution Investment

Q26. Please identify the numerous investments NIPSCO has made in its transmission and distribution system since the 45159 Electric Rate Case.

A26. Since the 45159 Electric Rate Case, NIPSCO has made numerous investments in its transmission and distribution system. Most of NIPSCO's investment in the transmission and distribution system since the 45159 Electric Rate Case has been pursuant to its Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") Plans. NIPSCO's initial TDSIC plan for the period January 1, 2016 through May 31, 2021 was approved in Cause No. 44733. NIPSCO's current TDSIC plan for the period

June 1, 2021 through December 31, 2026 was approved in Cause No. 45557. NIPSCO has made significant investments in infrastructure upgrades pursuant to its TDSIC plans. Through January 31, 2022, NIPSCO TDSIC investments total more than $840 Million in direct costs. Some infrastructure upgrades executed through NIPSCO's TDSIC Plan include:

(a) Underground Cable Replacement. This program started in 2014 and stretches across NIPSCO's service territory, targeting early generation cable that was prone to failure. Since the inception of the program, NIPSCO has replaced a total of approximately 3.5 million feet of cable and conduit.

(b) Substation Relay Modernization. Relays protect the NIPSCO electric transmission and distribution system from undesired system conditions such as overvoltage, thermal overload, and short circuit. Relay modernization provides NIPSCO customers better service through reduced outage times and system visibility. The scope of these projects ranges from replacing mechanical relays, breaker replacements, upgrading protection schemes, and communication equipment to provide visibility and relay communication. Since the inception of the program, NIPSCO has modernized all its 345kV circuit protection relays, 83% of its 138kV circuit protection relays, and 72% of its 69kV circuit protection relays.

(c) Steel Structure Life Extension. Steel structures are subject to degradation through physical damage, ground conditions, and normal atmospheric conditions. NIPSCO's Steel Structure Life Extension program is designed to extend the life of steel structures or rehabilitate those that do not meet the accepted strength requirements. Since 2016, NIPSCO has coated and extended the life of over 2,700 structures through 2021. To date, approximately 70% of NIPSCO's steel structures have received this life extending treatment and rejuvenation. The Steel Structure Life Extension program is a cost-effective way to maintain reliability of the steel transmission structures within NIPSCO's electric service territory.

(d) 4kV Conversion Project. NIPSCO's 4kV Conversion Project modernized outdated circuits mainly located throughout the northern portion of NIPSCO's service territory. The program consisted of upgrading or retiring assets such as poles, wire, transformers, and substations to a more modern construction standard, resulting in a more reliable and easier to restore system. NIPSCO completed the 4kV conversion project in 2021. A total of 19 4 kV circuits totaling approximately 33.8 circuit miles were upgraded to 12.5 kV, and seven 4 kV substations were retired.

Q27. Please identify investments NIPSCO is currently undertaking in its transmission and distribution system that are planned to be in-service by the end of the Forward Test Year (December 31, 2023).

A27. The investments NIPSCO is currently undertaking in its transmission and distribution system that are planned to be in-service by the end of the Forward Test Year are as follows:

(a) 138Kv Synchronous Condenser. This project includes the installation of a new 138 kV Synchronous Condenser, which will replace the Unit 8 Synchronous Condenser conversion (completed in 2018). The Synchronous Condenser will have a rating of +360/-180 Megavolt Ampere Reactive Power (MVAR) and will be a long-term solution for short circuit and voltage support on the local 138 kV electrical system. This investment is needed to support NIPSCO's transition to renewable energy.

(b) LNG to Stillwell. This project was identified in connection with NIPSCO's integrated resource plan to prepare for the retirement of Schahfer. This project includes a 138 kV circuit upgrade with new monopole towers and larger current carrying conductor.

(c) Shoreline Substation. Michigan City is one of NIPSCO's oldest 138 kV substations, with drawings for the original facility dating back nearly 100 years, to the year 1926. The current substation configuration includes one breaker for every line and one breaker for the transfer bus. The failure of a breaker or fault on the transfer bus results in an outage at the entire substation. In the new bus configuration, three breakers are required for every two circuits. Utilizing this configuration, any circuit breaker can be isolated and removed for maintenance without interrupting supply of any of the other circuits. The breaker and a half scheme is very flexible and highly reliable. This bus configuration will improve system safety and performance by preventing errors tied to the existing complex bus configuration during switching operations and allow for ease of future maintenance activities. The substation will be relocated and completely rebuilt to current standards to increase safety, operability, and compliance. The scope of this project includes replacement of the remainder of the 138 kV breakers and their ancillary equipment and an entirely new relay house. This is an approved project under NIPSCO's current electric TDSIC Plan.

(d) Electric Control Center. A new electric control center is being constructed to improve communications and operations of the NIPSCO electric operations department. The project will co-locate Transmission Operations, Generation Operations, Distribution Operations, Operations Dispatch, Operation Planning, Compliance Training, Security Operations Center, and Operations Technology. Construction is expected to begin in late 2022 with most construction taking place through the end of 2023 and into 2024. This new facility will improve internal and external operations communication, coordination, and situational awareness. Other benefits include integrated transmission and distribution outage management and emergency response coordination. The new facility will be able to accommodate new technology systems, including Advanced Distribution Management Systems and Advanced Metering Infrastructure.

Q28. Are there any transmission facilities that are not included in NIPSCO's jurisdictional rate base in this case?

A28. Yes. NIPSCO owns and operates certain transmission facilities which are treated as non-jurisdictional assets as approved in Cause Nos. 44156-RTO-1, 13, and 19. These transmission facilities consist of two Multi Value Projects, four Targeted Market Efficiency Projects, and one Interregional Market Efficiency Project as defined by MISO and further described in the RTO proceedings listed. As these projects were granted non-jurisdictional treatment, they are excluded from jurisdictional rate base in this case.

Q29. In your opinion, are NIPSCO's jurisdictional transmission and distribution plant and equipment used and useful in the provision of electricity to NIPSCO's retail electric customers?

A29. Yes. NIPSCO's jurisdictional transmission and distribution plant and equipment are essential to the reliable transport and delivery of electricity from NIPSCO's generation fleet (or from other generators) to its retail customers to meet customers' needs for electric power.

Customer Service and Reliability[1]

Q30. Please summarize the reliability metrics associated with NIPSCO's transmission and distribution system since the 45159 Electric Rate Case.

A30. NIPSCO monitors three main metrics to evaluate the reliability of the transmission and distribution system: SAIFI, SAIDI and CAIDI (the "reliability metrics"). SAIFI is the System Average Interruption Frequency Index and represents the average number of times that a system customer experiences an outage during the year. SAIDI is the System Average Interruption Duration Index and represents the number of minutes a utility's average customer did not have power during the year. CAIDI is the Customer Average Interruption Duration Index and represents the average time of an outage during the year.

NIPSCO's reliability indices, SAIFI, SAIDI, and CAIDI, have increased since the 45159 Electric Rate Case. As shown in Figure 2 below, when

[1] As noted above, additional information on NIPSCO's customer service and reliability metrics is available in its PMC Report filed on July 1, 2022, in Cause No. 44688.

looking at the reliability metrics from an all-inclusive perspective, NIPSCO has seen increases in SAIFI, SAIDI, and CAIDI. NIPSCO believes this is a result from the number of Major Event Days ("MED") it has experienced over the years. MED are primarily storms or severe weather events that are more destructive than typical storm events. Figure 3 below illustrates the number of MED in NIPSCO's service territory and the threshold that was used to identify major event days each year. As shown in Figure 3, NIPSCO has seen an increase in MED in recent years, due to stronger storm activity across the service territory. Furthermore, NIPSCO has seen an increased number of MED in the last 4 years, with two of the highest number of MED in 2019 and 2021. The increase in MED and associated restoration days in 2021 is the result of increased severe weather in 2021, with 10 MED, which is the highest in the past 10 years.

When looking at the reliability metrics, without MED, NIPSCO has held steady in regard to SAIFI, since the 45159 Electric Rate Case. This can be attributed to: (1) increasing NIPSCO's vegetation management funding in its distribution and transmission circuit program; (2) execution of the TDSIC plan providing system resiliency; and (3) NIPSCO's Outage

Investigation Program which targets outages that resulted in over 1,000 customers affected. NIPSCO expects to see additional improvement in SAIFI, as it continues investing in its vegetation circuit trimming and executing its current TDSIC plan, which includes hardening the system with new wood poles, replacing older vintage underground cable, and deploying additional distribution automation.

As far as SAIDI and CAIDI, without MED, NIPSCO has seen the metrics increasing since the 45159 Electric Rate Case. Even though NIPSCO owns five mobile substations to assist with construction activities, NIPSCO still has the need in many cases to tie circuits to adjacent substations or circuits during construction activities. Therefore, when an outage occurs on circuits that are tied, the number of customers impacted is increased. NIPSCO expects to see improvements in both SAIDI and CAIDI with the execution of its current TDSIC plan, which includes "Grid Modernization" investments, through which NIPSCO will provide value to its customers by reducing outage severity and duration, thereby improving the customer experience.

Figure 2. NIPSCO Reliability Metrics (Including MED)

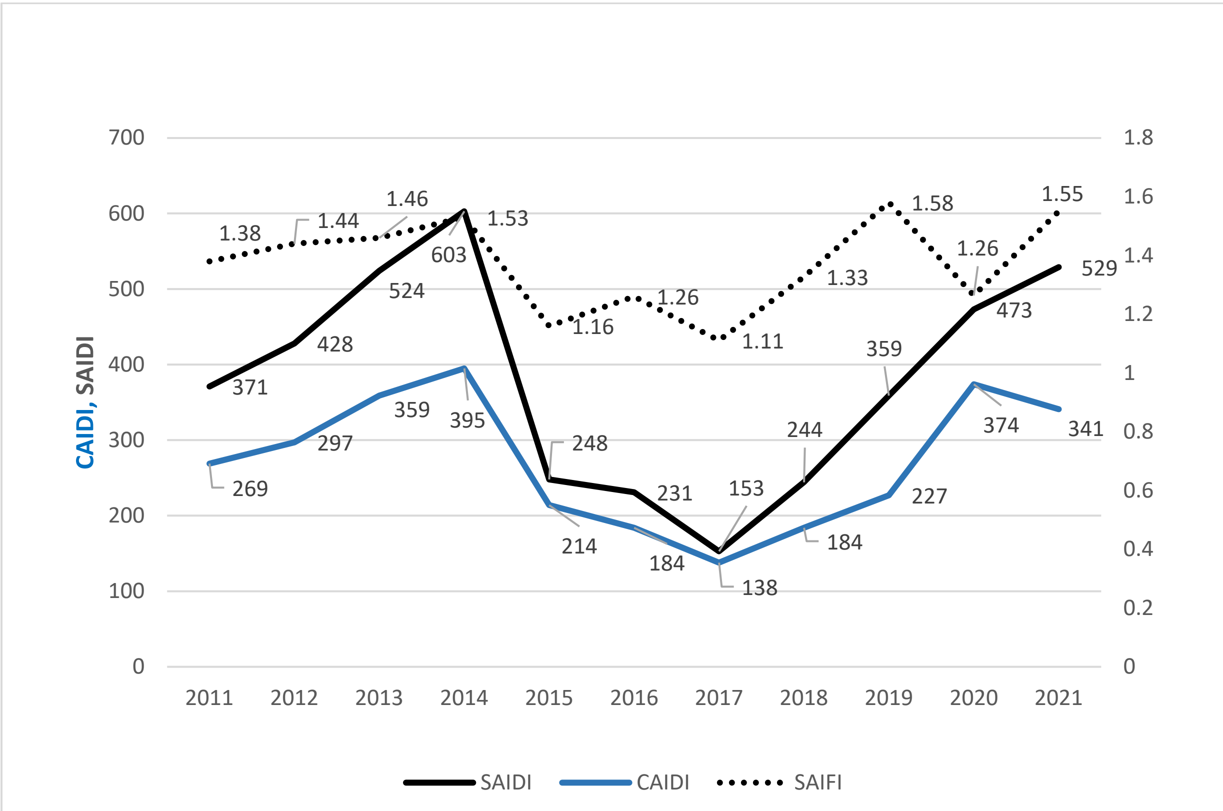
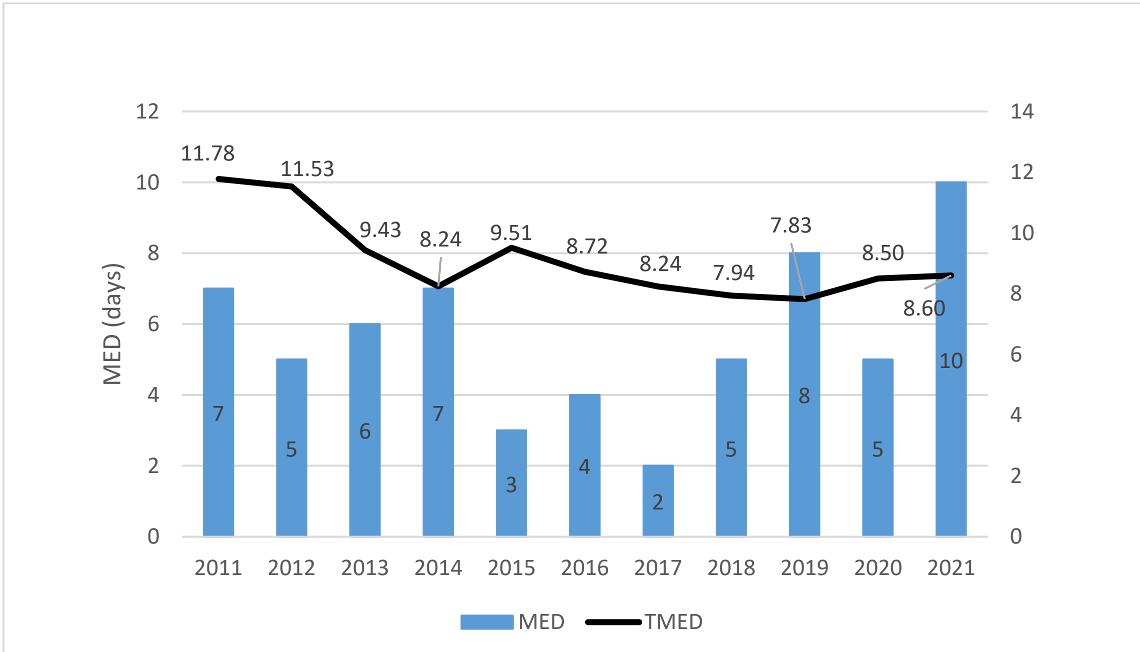


Figure 3. NIPSCO's Major Event Days Metrics



Q31. Are NIPSCO's transmission and distribution reliability metrics in line with industry standards?

A31. Yes. NIPSCO uses the Institute of Electrical and Electronics Engineers ("IEEE") Standard 1366-2012 when calculating the metrics for SAIFI, SAIDI, and CAIDI. Overall, NIPSCO has been holding steady when compared to its peers. Figure 4 shows that NIPSCO's SAIFI has been lower (better) than the IEEE industry median for medium-sized utilities over the past 10 years. Figure 5 shows that NIPSCO's SAIDI has been below or slightly above the

IEEE industry median for medium-sized utilities over the past 10 years.[2] NIPSCO saw an increase to SAIDI in 2021 because of a high number of severe weather days (27) impacting its customers. A severe weather day for NIPSCO is determined when 20% of the Threshold Major Event Day ("TMED") calculation for the year is met (TMED is referenced in Figure 3).

Finally, Figure 6 shows that NIPSCO's CAIDI has been above the IEEE industry median for medium-sized utilities over the past 10 years. Similarly, as in the case for SAIDI, NIPSCO also saw an increase to CAIDI in 2021 because of a high number of severe weather days (27) impacting its customers and workforce availability impacts from COVID-19 worker safety protocols.

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[2] IEEE Standard 1366-2012 Beta Method using a utility's daily SAIDI values for the past five reporting years.

Figure 4. SAIFI (excluding Major Events)

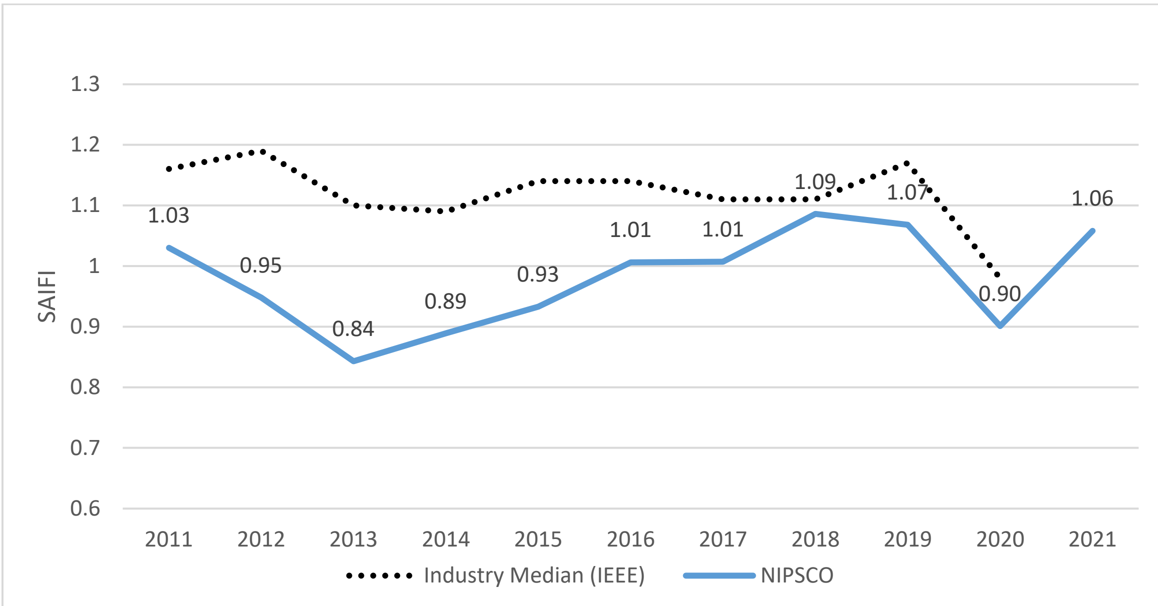


Figure 5. SAIDI (excluding Major Events)

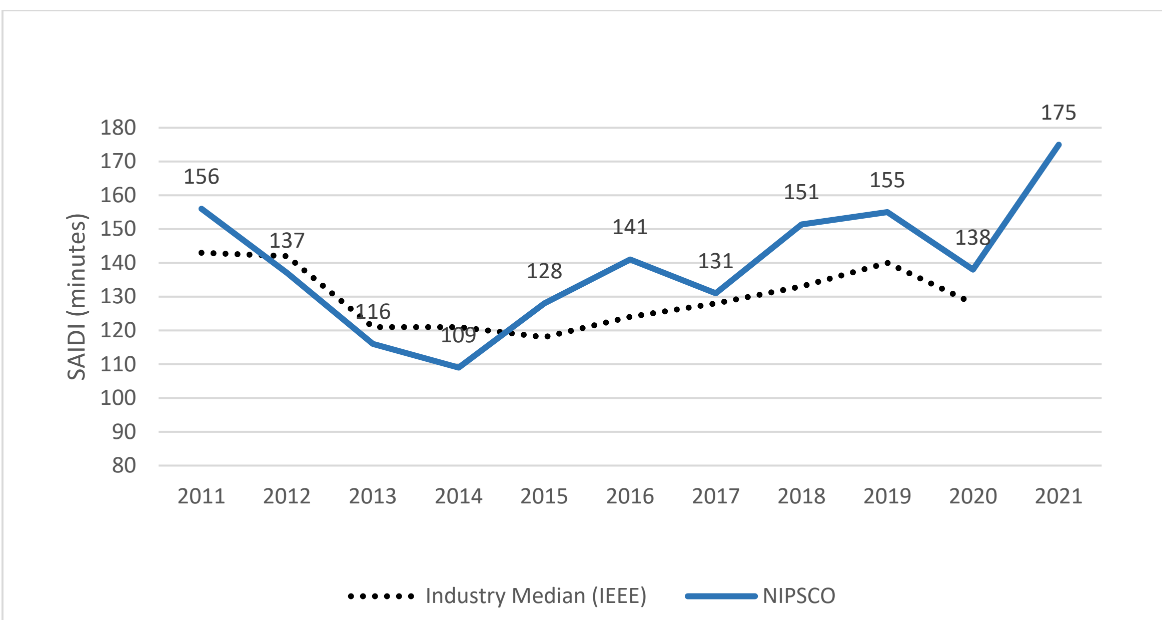
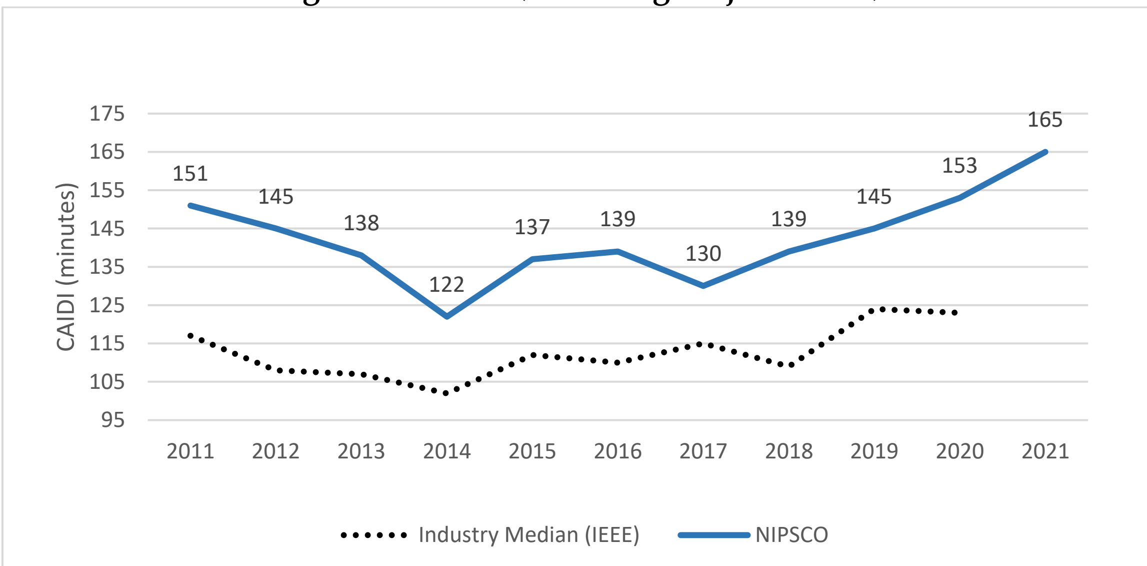


Figure 6. CAIDI (excluding Major Events)



Q32. What types of maintenance programs are in place at NIPSCO to ensure electric system reliability?

A32. NIPSCO has a comprehensive set of proactive substation, transmission, and distribution maintenance programs targeted at reliability. These include an active vegetation management program and capital investments aimed at enhancing system capabilities, improving reliability, and replacing aging infrastructure where needed. NIPSCO also continues to review and enhance its transmission system maintenance program procedures and record systems to improve reliability, reduce mis-operations, and ensure compliance with North American Electric Reliability Corporation standards.

NIPSCO is currently operating its wooden structure inspection program on a 10-year cycle. This program includes the treatment/life extension of poles meeting minimum strength requirements and replacement of those that do not meet those requirements. The pole program inspects approximately 30,000 wooden transmission and distribution poles per year and replaces a minimum of 1,200 poles on an annual basis. A similar program has been implemented for NIPSCO's steel structures, which includes the inspection, remediation, and coating of NIPSCO's steel lattice structures and monopoles. Currently this program operates on a 20-year cycle and includes structures both outside and inside of substations.

Other system reliability programs include the periodic inspections and maintenance of transmission lines and structures, substation equipment, protective relay systems, and distribution pad-mount transformers, pole-mounted reclosers, voltage regulators, switched capacitors, and other underground equipment. These programs also include the remedial work necessary to repair or replace minor plant items found to be deficient from inspection criteria.

Q33. How does NIPSCO's TDSIC plan address system reliability?

A33. One focus of NIPSCO's TDSIC plan is reducing system risk by addressing projects related to aging infrastructure. These projects focus on mitigating assets that have high likelihood of failure, as well as a high consequence of failure. By doing this, NIPSCO can prioritize those assets that will have the highest probability of failing that will also have the largest impact to NIPSCO's customers, as well as safety and environmental impacts.

A specific example of the reliability improvements NIPSCO's customers have experienced can be quantified through the execution of the Underground Cable Replacement program. This program focuses on 1970s and 1980s vintage unjacketed cable, which accounts for 90% of the underground faults each year. NIPSCO focused its replacement on the impact of a failure and the frequency of failures. With this, over the last 10 years, NIPSCO has decreased the number of customers affected each year by an underground fault from over 10,000 to under 8,000, a 20% improvement. Execution of this program has also decreased the number of underground faults on NIPSCO's system from over 300 to just above 200 each year; a 33% improvement.

Q34. In addition to the maintenance programs described above, what other actions has NIPSCO undertaken to maintain and/or improve customer service and reliability?

A34. On an annual basis, NIPSCO reviews and, if needed, makes adjustments to its Electric Emergency Response Plan ("EERP"). The EERP is a coordinated and comprehensive response plan for rapid restoration of electric service in the event of severe weather, or other system emergencies, by ensuring that all required corporate resources are utilized in the most effective manner.

In addition, NIPSCO continues its formal Outage Investigation Program. This Program reviews any outages that impact more than 1,000 customers, result in a pole fire or similar safety-related event, or have an outage cause code of "unknown." The findings are reported out through the organization. Lineman, Substation Electricians, Supervisors, Dispatchers, and Engineers all benefit from these report findings by applying these lessons learned to their designs, materials, and construction methods to improve reliability. This Program also reviews and updates the outage cause codes to identify the true outage root cause. Doing so allows NIPSCO to perform analytics more accurately on its outage causes and make improved decisions on materials, designs, construction methods, and maintenance techniques. This Program averages 110 investigations per year and is made up of the most impactful outages to NIPSCO's customers.

NIPSCO maintains a Line & Substation voltage regulator maintenance replacement program to reduce service failures leading to enhanced customer reliability. Newer design regulators incorporate enhanced tap changers that reduce contact wear and thus premature failure. Microprocessor based controls have been more reliable than analog controls, with the added benefit of enhanced customer voltage profile.

NIPSCO continues to perform its Circuit Performance Improvement Program to better improve electric system reliability. The Program includes calculating the SAIFI, SAIDI, and CAIDI, and Customer Duration Hours annually for each circuit and determining an overall performance value for each circuit. The circuits with the worst performance values are then assessed and recommendations for improvement are developed. The Program includes identifying all taps that have experienced multiple outages in the previous year and developing recommendations for improvement. Recommendations for improvement for the Circuit Performance Improvement Program include targeted tree trimming, replacement of equipment prone to failure, replacement of equipment that is in poor condition, an analysis of fuse coordination and loading, and installing additional sectionalizing devices (Cut-Outs, Triple-Shots, Reclosers, Switches, etc.), where appropriate, to minimize the impacts of outages and the number of customers affected per outage.

NIPSCO has commenced rollout of a modern distribution automation ("DA") system to replace NIPSCO's current aged DA system. This system will help to sectionalize NIPSCO's customers down to 500 count sections, which reduces the number of customers affected by a system interruption. It will also help pinpoint the cause of the interruption, further reducing the time needed to patrol the affected circuit to find the defect.

NIPSCO has also completed its investment in an Enhanced Outage Management System ("EOMS") to improve customer experience by providing for faster restoration and more accurate communication of estimated time of restoration during planned and unplanned outages. Overall, the EOMS will serve as the foundational platform to drive dependable, predictable, timely service and emergency response.

Finally, to enhance customer experience, NIPSCO improved its mobile user application to show the outage cause when NIPSCO has updated the estimated time of restoration ("ETR"). All electric customers that have supplied NIPSCO with an email address were auto-enrolled to receive power outage email alerts. NIPSCO also allows customers to enroll themselves to receive Account Alert notifications via text and/or voice message for unplanned electrical outages and ETR notifications. This information allows NIPSCO to inform customers on the duration of the outage so customers can plan their day accordingly.

Q35. Has NIPSCO seen reductions in tree-related outages events?

A35. Except for 2021, NIPSCO has seen an overall reduction of Tree Related Outages ("TROs") since 2016. As shown in Table 4 below, 2021 had a high number of localized weather-related events. When comparing the 3-year period 2016 to 2018 and 2019 to 2021 in Table 5, NIPSCO's average tree related outages improved from 3,637 (2016 to 2018) to 3,060 (2019 to 2021). This improvement is encouraging, considering NIPSCO has experienced more weather event days from 2019 to 2021 compared to 2016 to 2018 and confirms NIPSCO is targeting the correct circuits that is causing the most customer outages. However, NIPSCO is moving to a more proactive approach that focuses on its distribution and sub-transmission circuits.

Table 4

Tree Related Outages (Excluding Major Events)		
	Outages	Severe Days
2016 Tree Outages	3705	15
2017 Tree Outages	3610	16
2018 Tree Outages	3595	20
2019 Tree Outages	3056	29
2020 Tree Outages	2892	15
2021 Tree Outages	3233	27

Table 5

3-Year Period	Avg. Tree Outages (Excluding Major Events)	Avg. Severe Days	Avg. MED
2016 – 2018	3,637	17	3.6
2019 – 2021	3,060	23.6	7.6

Q36. What vegetation management cycle is NIPSCO currently on for its distribution and sub-transmission circuit program?

A36. On average for the last three years, NIPSCO has trimmed approximately 750 circuit miles per year. Assuming this pace continues, NIPSCO would trim each mile of circuit once every 11 years. However, NIPSCO's experience is, on average, trees grow back into the lines within a 5-year period. In order to trim or clear each of its distribution and sub-transmission circuits every 5 years, a significant number of additional crews would need to be utilized and would cover about 1,600 miles per year.

Q37. What is the biggest challenge NIPSCO faces to be able trim each circuit every 5 years?

A37. Public and employee safety is NIPSCO's utmost priority when performing work. Consequently, NIPSCO only partners with contractors who specialize in this kind of work and have proven experience in tree clearing around energized lines. NIPSCO has been working with its labor contractors to develop a plan to ramp up staffing in a prudent and responsible way to recruit, train, and retain talent to work on energized lines. In fact, NIPSCO has begun onboarding crews starting in 2022 and will continue this steady approach until meeting the staffing requirements, which is currently targeted to conclude in the last quarter of 2023. Getting to the place where each circuit mile is cleared every five years would require additional crews and additional expenditures, especially with the tight labor market and cost increases, which are discussed further below.

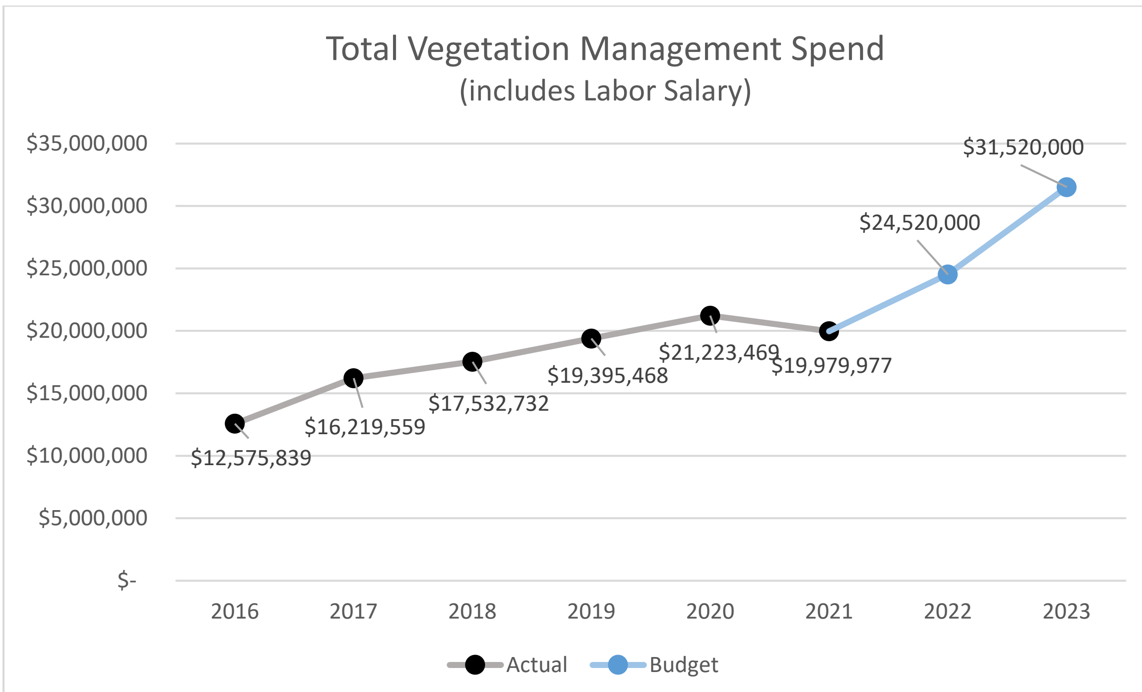
Q38. How are customer service and reliability goals incorporated into NIPSCO's planning process?

A38. NIPSCO prepares an annual operating plan to outline long term and near-term operational goals, plans, and performance targets. Key elements of this plan include a focus on service and reliability improvements. Performance targets are established that represent stretch levels of continuous improvement and initiatives are then outlined to achieve the performance targets. These performance targets and initiatives are then cascaded throughout the organization in an aligned and increasingly more specific manner, becoming a core part of the annual performance management process. NIPSCO's performance initiatives are directly tied to reliability metrics (SAIFI, SAIDI, and CAIDI), safety metrics (OSHA recordables, DART, and PVCs), and staying within operation budget, and targets for these metrics are included in performance expectations.

Q39. Please describe NIPSCO's Vegetation Management Program.

A39. To improve reliability, as shown in Figure 7 below, NIPSCO has steadily increased funding for its vegetation management program to specifically focus on trimming more circuit miles on distribution and sub-transmission circuits. NIPSCO has used the majority of the budget increase to clear circuits that have the highest tree-related outages.

Figure 7. Total Vegetation Management Spend



Over the years, the line mile cost has become more expensive. NIPSCO has experienced increases in the cost of performing line clearance tree trimming from its preferred vendors. Tight labor markets, competition for labor of neighboring utilities, and increases in fuel and equipment costs, have all led to increasing the cost to perform the work.

In 2017, NIPSCO Vegetation Management held a category specific sourcing event with vendors to secure pricing for multi-year contracts. The sourcing strategy performed in 2017 and renewed in 2021 fundamentally changed the way NIPSCO performs line clearance activity. The event moved NIPSCO to a unit-based model with a multi-year commitment from the preferred partners to lock prices for the term of the contract with a commitment from NIPSCO for steady and stable work during the contract term. This partnership has assisted the partners to secure resources to assist in controlling increases in costs.

Between 2021 and 2022, the cost for equipment has also increased. All categories of equipment saw an increase beyond the annualized inflation rate. Similarly, labor has increased for some of the individual labor classes. The increase in labor and equipment are primarily driven by the increased demand for resources across the industry and a tightening of the labor and equipment resources. According to NIPSCO contractors, the market constraints are due to the low unemployment rate, and other utilities increasing their demand for vegetation contractors.

Due to increases in contractor costs, NIPSCO's 2023 budget funding of approximately $30 million will provide for the completion of approximately 1,200 miles of line, which is slightly better than a 7-year cycle. The market adjustment increases will allow NIPSCO to continue to take steps to improve customer reliability and experience by reducing vegetation related outages.

<u>Pro-Forma Expense Adjustments</u>

Q40. Please describe Adjustment OM 2A-23R for Generation Maintenance Activity expenses shown on <u>Petitioner's Exhibit No. 3</u>, Attachment 3-C-S2, OM 2A.

A40. Adjustment OM 2A-23R is a rate making adjustment increasing the Generation Base Maintenance expense by $1,629,147 to reflect an historical (2019-2021) 3-year average. If this adjustment is not included, the Forward Test Year electric operating expenses will be understated. Details of this adjustment can be found in <u>Petitioner's Confidential Exhibit No. 22-S2</u>, Workpaper OM 2A.

Q41. Please describe Adjustments OM 2B-23R for Planned Outages expenses shown on <u>Petitioner's Exhibit No. 3</u>, Attachment 3-C-S2, OM 2B.

A41. Adjustment OM 2B-23R is a rate making adjustment decreasing the Planned Outages expense by $3,207,062 to reflect an historical (2019-2021)

3-year average. The planned outage schedule varies by year, and the workplan for each generating station details the projected expenditure amount by station, unit, and major component. If this adjustment is not included, the Forward Test Year electric operating expenses will be overstated. Details of these adjustments can be found in Petitioner's Confidential Exhibit No. 22-S2, Workpaper OM 2B.

Q42. Please describe Adjustments OM 2C-23R for Forced Outages expenses shown on Petitioner's Exhibit No. 3, Attachment 3-C-S2, OM 2C.

A42. Adjustment OM 2C-23R is a rate making adjustment increasing the Forced Outage expense by $1,053,877 to remove Schahfer Unit 14 and 15 and reflect an historical (2019-2021) 3-year average. If this adjustment is not included, the Forward Test Year electric operating expenses will be understated. Details of this adjustment can be found in Petitioner's Confidential Exhibit No. 22-S2, Workpaper OM 2C.

Q43. Please describe Adjustments OM 2D for Variable Chemicals expenses shown on Petitioner's Exhibit No. 3, Attachment 3-C-S2, OM 2D.

A43. Adjustment OM 2D-21 is a normalization adjustment decreasing the Historic Base Year expense by $897,199 to remove variable chemicals associated with Schahfer Unit 14 and 15. If this adjustment is not included, the Historic Base Year electric operating expenses will be overstated. Details of this adjustment can be found in Petitioner's Confidential Exhibit No. 22-S2, Workpaper OM 2D.

Q44. Please describe Adjustments OM 2E for Nontrackable Fuel Handling expenses shown on Petitioner's Exhibit No. 3, Attachment 3-C-S2, OM 2E.

A44. Adjustment OM 2E-21 is a normalization adjustment decreasing the Historic Base Year expense by $7,923,431 to remove nontrackable fuel handling expense associated with Schahfer Unit 14 and 15. If this adjustment is not included, the Historic Base Year electric operating expenses will be overstated. Details of this adjustment can be found in Petitioner's Confidential Exhibit No. 22-S2, Workpaper OM 2E.

Q45. Please describe Adjustments OM 2G for Line Locates expenses shown on Petitioner's Exhibit No. 3, Attachment 3-C-S2, OM 2G.

A45. Adjustment OM 2G is a rate making adjustment increasing the Line Locates operating expenses by $1,602,370. Overall, NIPSCO has experienced increases in the volume of line locate tickets year-over-year. The proposed adjustment reflects an 11.75% ticket volume increase, based on a 4-year average. The main driver of the volume is attributed to increases in public marketing and awareness regarding calling 811 for a locate ticket and increases in fiber and infrastructure investments occurring across the service territory.

The pro forma adjustment also reflects incremental cost per ticket increases, which include labor rate increases to retain talent and price increases to perform audits at a 10% rate (up from 5% in 2021) to ensure better quality of locates. If this adjustment is not included, the Forward Test Year electric operating expenses will be understated. Details of this adjustment can be found in Petitioner's Confidential Exhibit No. 22-S2, Workpaper OM 2G.

Q46. Please describe Adjustments OM 2I for Non-jurisdictional expenses shown on Petitioner's Exhibit No. 3, Attachment 3-C-S2, OM 2I.

A46. Adjustment OM 2E-23 is a rate making adjustment decreasing the Non-jurisdictional expense by $474,915 to remove non-jurisdictional expense based on the monthly average for January to May 2022 actuals. If this adjustment is not included, the Forward Test Year electric operating expenses will be overstated. Details of this adjustment can be found in Petitioner's Confidential Exhibit No. 22-S2, Workpaper OM 2I.

Q47. Does this conclude your prefiled direct testimony?

A47. Yes.

VERIFIED DIRECT TESTIMONY OF RONALD E. TALBOT

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

A1. My name is Ronald E. Talbot. My business address is 801 East 86th Avenue, Merrillville, Indiana 46410. I am the Senior Vice President, Electric Operations for Northern Indiana Public Service Company LLC ("NIPSCO").

Q2. Please briefly describe your educational and business experience.

A2. I have served as the Senior Vice President of Electric Operations responsible for leading the organization's power delivery, electric generation, and transmission functions since April 2020. I have more than 30 years of experience of strategic problem solving and process improvement in the utility industry and have held a number of senior officer roles spanning operations, safety, IT and supply chain, as well as consulting. I served as the senior vice president and Chief Operating Officer ("COO") of PNM Resources until February 2017, where I was responsible for all vertically integrated utility operations for Public Service New Mexico, and I was also responsible for overseeing Texas New Mexico Power. I was appointed

COO of Indianapolis Power and Light ("IPL") (now AES Indiana) in June of 2011. Prior to serving as COO, I served as Senior Vice President Power Supply beginning in March of 2007, and was responsible for IPL's generating stations, fuel procurement, generation dispatch, and wholesale trading. I joined IPL as Senior Vice President of Customer Operations in August 2003. Previously, I was Vice President of Chicago Region Operations for Commonwealth Edison Company in Chicago from December 1999 to April 2002. Prior to that, I worked for approximately 15 years in various capacities for Consolidated Edison in New York, including General Manager of Staten Island Electric Operations and later General Manager of Manhattan Electric Operations. I have baccalaureate degrees in economics from SUNY Oneonta and in electrical engineering from Clarkson University, as well as a Master of Science in Electrical Engineering from the New Jersey Institute of Technology. Over the course of my career, I have also served on numerous industry and not for profit boards of directors.

Q3. What are your current responsibilities as Senior Vice President, Electric Operations of NIPSCO?

A3. As Senior Vice President, Electric Operations, I am responsible for all aspects of NIPSCO's electric operations, including NIPSCO's electric transmission and distribution system, as well as NIPSCO's generating assets.

Q4. Have you previously testified before the Indiana Utility Regulatory Commission ("Commission") or any other regulatory commission?

A4. Yes. I filed testimony before the Commission in Cause No. 38706-FAC-130-S1. I have also made several presentations before the Commission and staff, as well as before New Mexico Public Regulation Commission.

Q5. Are you sponsoring any attachments to your testimony in this Cause?

A5. No.

Q6. What is the purpose of your testimony?

A6. The purpose of my testimony is to: (1) describe NIPSCO's generation fleet; (2) describe NIPSCO's electric transmission and distribution systems; (3) discuss the Company's customer service and electric reliability programs; (4) describe the significant investments NIPSCO has made to its generation and transmission and distribution systems in recent years; and (5) explain various pro-forma expense adjustments.

Q7. Has NIPSCO made significant investments in its electric facilities that is driving the relief sought in this case?

A7. Yes. Approximately three years have passed since the test year used to establish NIPSCO's current rates. During that time period, NIPSCO has invested significantly in its infrastructure related to its jurisdictional electric operations, and this is expected to continue through the end of the Forward Test Year (December 31, 2023) for this proceeding. NIPSCO's generation transition and modernization of its transmission and distribution systems have driven the overwhelming majority of these investments.

<u>NIPSCO's Generation Fleet</u>

Q8. Are you familiar with NIPSCO's generating facilities?

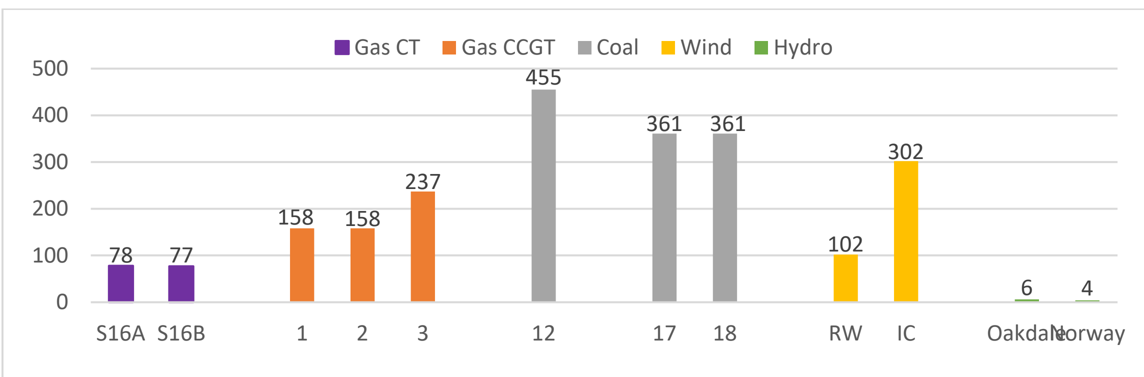
A8. Yes.

Q9. Please generally describe NIPSCO's generation fleet.

A9. The NIPSCO generating facilities have a total installed capacity of 2,299 net megawatts ("MW") and consist of seven (7) separate generation sites, including the R.M. Schahfer Generating Station ("Schahfer" or "RMSGS") (Units 16A, 16B, 17 and 18), Michigan City Generating Station ("Michigan City" or "MCGS") (Unit 12), Sugar Creek Generating Station ("Sugar

Creek" or "SCGS") (SC1, SC2, and SS1), Rosewater Wind Farm ("Rosewater"), and Indiana Crossroads I Wind Farm ("Crossroads Wind I") and two (2) hydroelectric generating sites (Oakdale and Norway). Of the total capacity, 51.20% is from coal-fired units, 30.80% is from natural gas-fired units, 17.57% is from renewables (wind), and 0.43% is from hydroelectric units. Figure 1 illustrates the installed net capacity and unit identification of NIPSCO's generating units.

Figure 1. Installed net capacity of generating units (MW)



Q10. What changes has NIPSCO made to its generation fleet since its last electric rate case in Cause No. 45159 ("45159 Electric Rate Case")?

A10. Since the 45159 Electric Rate Case, NIPSCO (a) retired Unit 10 at Bailly Generating Station (as of July 15, 2020) and Units 14 and 15 at Schahfer (as of October 2021), and (b) added Rosewater (as of December 2020) and Crossroads Wind I (as of December 2021).

Q11. Have there been other planned changes to NIPSCO's generation fleet since the 45159 Electric Rate Case?

A11. Yes. Following NIPSCO's 2018 Integrated Resource Plan ("IRP") and coming out of the 45159 Electric Rate Case, NIPSCO expected that Schahfer Units 17 and 18 would retire no later than May 31, 2023, which was contingent upon the development and completion of the remaining portfolio of renewable projects to replace the energy and capacity of the units. However, based on delays to NIPSCO's planned renewable generation projects, which is further discussed by NIPSCO Witness Campbell, NIPSCO announced in May of 2022 that Units 17 and 18 would continue to operate beyond May of 2023 and would retire by the end of 2025. NIPSCO Witness Augustine explains the evaluation NIPSCO undertook that led to this decision, but, in short, the decision was made to ensure NIPSCO could reliably and adequately serve its customers as it continues execution of its generation transition.

Q12. What was the driver of NIPSCO's decision to extend operation of Units 17 and 18?

A12. Throughout NIPSCO's generation transition, providing reliable service to its customers has been top-of-mind. Based on various market factors beyond NIPSCO's control, which are discussed by NIPSCO Witness Campbell, it became apparent that some of NIPSCO's solar and solar plus storage projects originally anticipated to come online in 2023 would be delayed. This led NIPSCO to evaluate the best path forward under these uncertain circumstances. There were two primary alternatives NIPSCO evaluated. First, NIPSCO could continue with the planned retirement of Units 17 and 18 by May 31, 2023 and look to fill the capacity need associated with delayed renewable projects with other resources—which would have primarily been bilateral agreements. Second, NIPSCO could delay the retirement of Unit 17 and 18 and use these existing generation resources through 2025. Ultimately, NIPSCO determined utilizing these existing baseload, dispatchable resources to serve customers was the best decision to ensure NIPSCO continues to provide reliable and adequate service to its customers and meet reliability obligations to the Midcontinent Independent System Operator, Inc. ("MISO"). NIPSCO Witness Augustine discusses additional economic analysis performed in 2022 at NIPSCO's direction that supports this decision as well.

Q13. What investments has NIPSCO made to its generation fleet since the 45159 Electric Rate Case?

A13. Since the 45159 Electric Rate Case, NIPSCO has made significant investments in its transition to renewable generation. As noted above, Rosewater and Crossroads Wind I are both now in-service. There are two additional renewable generation projects forecasted to be online in 2023: (1) Indiana Crossroads Solar Park ("Crossroads Solar") and (2) Dunn's Bridge I Solar Park ("Dunn's Bridge I"). Significant capital investments to the NIPSCO generation fleet that were placed in-service since the 45159 Electric Rate Case (or forecasted to be in-service by the end of the Forward Test Year (December 31, 2023)), including the investments in NIPSCO's transition to renewable generation, are shown in Table 1 below:

Table 1

Facility	Description	Direct Capital (in millions)
2020 In Service		
MCGS	Seawall Upgrades	$2.14
Oakdale	#2 Generator and Turbine Overhaul	$1.21

Facility	Description	Direct Capital (in millions)
R.W.	Rosewater 102MW Wind Farm	$89.90
RMSGS	Unit 18 Turbine Valve Replacements	$1.05
	2021 In Service	
I.C.W.	Indiana Crossroads 302MW Wind Farm	$302.58
MCGS	Coal Car Dumper Feeder and Chute Replacement	$3.11
MCGS	Coal Car Thaw Shed Heater Replacements	$1.10
MCGS	Unit 12 Cooling Tower Fill, Drift Eliminator, and Louver Replace	$1.41
MCGS	SCR Catalyst Layer 4 Replacement	$1.20
MCGS	North ID Fan Rotor Replacement	$1.00
Oakdale	Concrete Rehabilitation	$2.42
RMSGS	Leachate Pipeline Project to Waste Water Treatment Facility	$1.11
RMSGS	Stalbaum Ditch Drainage Improvement Project	$1.19
SCGS	Boiler Feed Pump Replacements	$4.61
	2022 In Service / Forecast	
MCGS	SCR Catalyst Layer 1 Replacement	$1.39
Norway	Control System Upgrade	$1.50
Oakdale	Control System Upgrade	$1.50
Oakdale	Oakdale Flood Gate and Stop Log Replacements	$4.24
RMSGS	Unit 16A Turbine Major Overhaul	$5.87
	2023 Forecast	
D.B.	Dunn's Bridge I 265MW Solar	$233.74
I.C.S.	Indiana Crossroads 200 MW Solar	$191.07
MCGS	High Energy Valve Replacements (240/260)	$1.00
MCGS	FGD Reactor Upgrade	$1.00
MCGS	Unit 12 Controls Upgrade	$1.70
MCGS	Unit 12 Water Cannons Upgrade	$1.02
Norway	Norway Flood Gate Replacements	$4.00
Oakdale	Oakdale Head Gate and Stop Log Replacements	$6.91
Oakdale	Scrollcase Rehabilitation	$1.73
Oakdale	Transformer and Substation Relocation	$1.44
SCGS	Advanced Gas Path Upgrade	$20.7
SCGS	GT1 Flared 7A Enhanced Compressor Upgrade	$6.05
SCGS	Spare Generator Step Up Transformer	$3.04
SCGS	LTSA Hot Gat Path Inspection and Repairs	$14.08

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Q14. Please describe improvements made at Sugar Creek and how those improvements will impact customers.

A14. In the fourth quarter of 2023, Sugar Creek will have completed two large projects with benefits to customers beginning in November 2023. First, an Advanced Gas Path Upgrade will replace key components within the gas turbines to increase overall facility capacity by 40 to 46 MW depending on ambient operating conditions. These modifications will allow for greater unit dispatchable output as well as improved heat rate. There are increased maintenance costs associated with this upgrade, but the expected net present value of the project overall is approximately $10.5 million. Second, the GT1 Flared 7A Enhanced Compressor Upgrade is replacement of original components in the gas turbine compressor sections with upgraded components providing for longevity and reliability. These upgrades, directly address capacity concerns in addition to setting Sugar Creek on a path to sustained high capacity factor and availability, while maintaining a low Effective Forced Outage Rate.

Q15. Does NIPSCO regularly report to the Commission and stakeholders on key reliability metrics?

A15. Yes. Coming out of Cause No. 44688, which is the NIPSCO electric rate case preceding the 45159 Electric Rate Case, NIPSCO was required to file an annual Performance Metrics Collaborative ("PMC") Report. This Report includes sections on Safety, Reliability, Customer Service, Investment & Spending, and other items. I discuss some of these topics below, but NIPSCO's most recent PMC Report was filed with the Commission in Cause No. 44688 on July 1, 2022.

<u>**Base Cost of Fuel and Coal Inventory Levels**</u>

Q16. What was NIPSCO's level of fuel expense in the Historic Base Period?

A16. The adjusted retail jurisdictional cost of fuel in the Historic Base Period reported in Petitioner's Exhibit No. 3, Attachment 3-B-S2, FPP Module was $416,398,339 (Line 1, Column A).

Q17. Were NIPSCO's retail jurisdictional fuel costs during the Historic Base Period reasonable?

A17. Yes. NIPSCO made (and continues to make) every reasonable effort to acquire fuel to provide electricity to its retail customers at the lowest fuel cost reasonably possible. As NIPSCO regularly explains in its quarterly fuel adjustment clause proceedings, NIPSCO purchases fuel (coal) pursuant to long-term contracts entered into using competitive bidding and on the spot markets. For gas-fired generators (combustion turbines and Sugar Creek), NIPSCO purchases natural gas pursuant to supply contracts that are entered into using a competitive bidding process. Historically, the natural gas supply contracts have been seasonal or annual in duration, ensure firm delivery of natural gas to the generator, and have competitive pricing options based upon prevailing market conditions. NIPSCO considers several factors in making fuel procurement decisions, including price, quality, suitability, environmental attributes, transportation costs and logistics, supplier availability, reliability, and diversity. Market factors also affect fuel purchases.

Q18. What was the coal inventory level in the Historic Base Period?

A18. The retail jurisdictional coal inventory level reported in Petitioner's Exhibit No. 3, Attachment 3-B-S2, RB Module for the Historic Base Period was $32,190,387 (Line 13, Column A)

Q19. Is this coal inventory level reasonable?

A19. Yes. This coal inventory level is consistent with NIPSCO's fuel inventory strategy, which was provided as part of the Minimum Standard Filing

Requirements. NIPSCO's fuel inventory strategy is designed to balance the costs associated with maintaining coal inventory with reliability to ensure units are available to supply energy during periods of high demand, extreme weather, or fuel transportation disruptions or mine production problems.

Q20. You mentioned above that NIPSCO now plans to retire Schahfer Units 17 and 18 no later than December 31, 2025, as opposed to no later than May 31, 2023. Has NIPSCO procured sufficient coal associated with this extension?

A20. Yes. Since announcing the change in expected retirement date for Units 17 and 18, NIPSCO was able to procure the coal necessary to continue operations through 2025. Specifically, NIPSCO has entered into a term Illinois Basin coal supply agreement with Peabody Coal Sales, LLC to cover a significant portion of anticipated coal supply requirements for the extension period.

<u>NIPSCO's Safety Culture</u>

Q21. Please describe NIPSCO's safety culture.

A21. NIPSCO's safety culture has continued to make progress over the years. In 2021, NIPSCO continued work on its Safety Management System ("SMS") by expanding the program into its Electric Operations. These efforts are making progress with NIPSCO's safety culture by addressing issues related to safety, through the SMS program, which is based on the American Petroleum Institute (API) Recommended Practice (RP) 1173. SMS is anchored by Core Four (4) Responsibilities which include, (1) Following Our Processes and Procedures; (2) Identifying and Reporting Risks; (3) Continually Improving Processes and Procedures; and (4) Identifying and Proactively Taking Action.

NIPSCO's SMS journey is intended to take safety to a new level of continuous improvement. It brings together people, processes, and culture to proactively find and act on risks to employees, contractors, customers, and communities. SMS drives learning from past experiences, enhanced risk models and input from teams on the front lines. These lessons drive improvements that protect customers and communities, along with employees and contractors. The Corrective Action Program ("CAP") is a foundational part of that effort. The Corrective Action Program offers a simple way to document identified risks and a systematic process to review, prioritize, address, and track progress to reduce them. Submitting an issue, concern, or risk in the Corrective Action Program starts a rigorous process that can lead to resolving a prioritized risk through corrective action.

To continue building a stronger safety culture, starting in 2021, NIPSCO began developing written programs for certain types of work that are considered High Consequence Tasks—critical operational processes that, if not performed properly, have the possibility of leading to a high consequence outcome and putting NIPSCO's teams, customers, and communities at risk. This 2021 initiative paid special attention to those riskiest tasks by developing guidelines to document critical operations and safety protocols. Employees and contractors review these guidelines before performing the work to be certain the processes and standards that apply are fresh in their minds. Employee feedback was incorporated into the design, providing a simple way to consistently navigate through the critical steps of High Consequence Tasks.

Q22. Have NIPSCO's safety metrics improved in recent years?

A22. Yes. As shown in Table 2 below, overall, NIPSCO has made a 34% improvement in the OSHA recordable injury rate, held steady in DART (days away, restriction or transfer) injury rate, and recorded a 10% improvement in PVC (preventative vehicle crash) incidents from year end 2012 to year end 2021. As shown in Table 3 below, in Electric Operations, NIPSCO has seen a 27% improvement in its OSHA recordable injury rate, a 9% downturn in DART (days away, restriction or transfer) injury rate, and a 46% improvement in PVC incidents from year end 2012 to year end 2021.

The recent downward trend in DART is due to COVID cases, medical case management by providers, and soft tissue injuries. COVID cases that are deemed work-related for recordability will tend to always follow in DART classifications and NIPSCO continues to monitor CDC guidance for strategies to implement to prevent and/or reduce workplace transmission of COVID. Additionally, medical providers are essentially changing to more conservative treatment methods and as a result, NIPSCO has noticed a rise in DART cases in recent years. NIPSCO continues to work with the NiSource Medical Director in obtaining access to the best available occupational health clinics in providing treatment to our employees. In certain instances, clinics have been replaced to better align with our vision and quality of care. Additionally, where soft tissue injuries have resulted in DART cases, the organization has recently implemented a new program called NIPSCO Moves that incorporates the latest advances in science for injury prevention utilizing the same techniques and principles incorporated by USA Olympic and professional athletes. The combined impact of these three areas on NIPSCO's DART rates should improve in coming years as our strategies for prevention and reduction are underway.

Table 2

NIPSCO Overall Performance ^^			
Year	OSHA Rate	DART Rate	PVC Incidents
2012	1.83	1.04	51
2013	1.50	0.93	45
2014	1.26	0.84	40
2015	1.23	0.65	47
2016	1.20	0.61	34
2017	0.75	0.33	38
2018	1.14	0.68	42
2019	1.33	0.88	57
2020	1.24	0.75	36
2021	1.20	1.04	46
^^ Includes all NIPSCO operations			

Table 3

NIPSCO Electric Stats			
Year	OSHA Rate	DART Rate	PVC Incidents
2012	2.46	1.54	26
2013	1.44	0.99	16
2014	1.41	0.97	20
2015	2.20	1.18	21
2016	2.23	1.37	13
2017	1.30	0.61	11
2018	2.23	1.61	21
2019	2.70	1.95	21
2020	2.61	1.59	13
2021	1.79	1.69	14

Q23. Does NIPSCO's focus on safety benefit customers?

A23. Yes. NIPSCO's focus on safety helps customers in a variety of ways. This focus ensures a healthier, more productive workforce while keeping the public as safe as possible. By keeping employees safer, NIPSCO is lowering costs for overtime or contracted work to replace an injured work force. NIPSCO is reducing hidden costs by preventing tired or less experienced employees from having to replace more experienced employees when they are injured. All other factors remaining constant, focusing on safety reduces NIPSCO's operating costs.

From a public safety and reliability standpoint, NIPSCO is using a risk-based prioritization approach as a guide in long-term system modernization planning. This approach identifies the highest-risk assets within the NIPSCO electric system and focuses mitigation planning on assets with the highest risk of failure. All major electric transmission and distribution assets, such as substation transformers, substation breakers and circuits, are included in this modeling approach. The scores derived from this risk model provide focus to high-risk assets and assist in prioritizing other areas of the business such as inspections, maintenance, load growth, and grid modernization. This approach helps keep NIPSCO's electric assets performing as anticipated and reducing overall risk of failure with a release of energy in public areas.

Additionally, NIPSCO is committed to educating the public about the importance of safe digging by promoting local 811 programs – the national, universal phone number and free service to call ahead of any digging project to have underground utilities marked. The number one cause of natural gas pipeline and underground electric primary damage is from third parties digging near underground facilities. NIPSCO focuses on educating the public about the importance of calling 811. Realizing its employees are NIPSCO's best advocates and connection to its customers and the communities we serve, NIPSCO added 811 logos to its company uniforms. National Safe Digging Month (April) and National Safe Digging Day (August 11) give NIPSCO opportunities to recognize and celebrate local partners in safe digging.

NIPSCO's Electric Transmission and Distribution Systems

Q24. Please describe NIPSCO's electric transmission system.

A24. 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 1,682 circuit miles of 69 kV transmission lines. In addition, NIPSCO has 66 transmission substations. NIPSCO is interconnected with seven neighboring utilities. The Company has transmission interconnects with American Electric Power or its affiliates, at the 345 kV, 138 kV, and 69 kV operating voltages. NIPSCO also interconnects with Commonwealth Edison at 345 kV and 138 kV and with Duke Energy Indiana at 345 kV, 138 kV and 69 kV and with NextEra Energy Transmission at 345 kV. NIPSCO has a single 138 kV interconnection with both Ameren and International

Transmission Company and a single 765 kV interconnection with Pioneer Transmission.

Q25. Please provide an overview of the NIPSCO electric distribution system.

A25. NIPSCO serves more than 483,000 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, and radiate from approximately 249 distribution substations. There are approximately 8,246 miles of overhead line with about 2,643 miles of underground cable.

<u>Transmission and Distribution Investment</u>

Q26. Please identify the numerous investments NIPSCO has made in its transmission and distribution system since the 45159 Electric Rate Case.

A26. Since the 45159 Electric Rate Case, NIPSCO has made numerous investments in its transmission and distribution system. Most of NIPSCO's investment in the transmission and distribution system since the 45159 Electric Rate Case has been pursuant to its Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") Plans. NIPSCO's initial TDSIC plan for the period January 1, 2016 through May 31, 2021 was approved in Cause No. 44733. NIPSCO's current TDSIC plan for the period

June 1, 2021 through December 31, 2026 was approved in Cause No. 45557. NIPSCO has made significant investments in infrastructure upgrades pursuant to its TDSIC plans. Through January 31, 2022, NIPSCO TDSIC investments total more than $840 Million in direct costs. Some infrastructure upgrades executed through NIPSCO's TDSIC Plan include:

(a) Underground Cable Replacement. This program started in 2014 and stretches across NIPSCO's service territory, targeting early generation cable that was prone to failure. Since the inception of the program, NIPSCO has replaced a total of approximately 3.5 million feet of cable and conduit.

(b) Substation Relay Modernization. Relays protect the NIPSCO electric transmission and distribution system from undesired system conditions such as overvoltage, thermal overload, and short circuit. Relay modernization provides NIPSCO customers better service through reduced outage times and system visibility. The scope of these projects ranges from replacing mechanical relays, breaker replacements, upgrading protection schemes, and communication equipment to provide visibility and relay communication. Since the inception of the program, NIPSCO has modernized all its 345kV circuit protection relays, 83% of its 138kV circuit protection relays, and 72% of its 69kV circuit protection relays.

(c) Steel Structure Life Extension. Steel structures are subject to degradation through physical damage, ground conditions, and normal atmospheric conditions. NIPSCO's Steel Structure Life Extension program is designed to extend the life of steel structures or rehabilitate those that do not meet the accepted strength requirements. Since 2016, NIPSCO has coated and extended the life of over 2,700 structures through 2021. To date, approximately 70% of NIPSCO's steel structures have received this life extending treatment and rejuvenation. The Steel Structure Life Extension program is a cost-effective way to maintain reliability of the steel transmission structures within NIPSCO's electric service territory.

(d) 4kV Conversion Project. NIPSCO's 4kV Conversion Project modernized outdated circuits mainly located throughout the northern portion of NIPSCO's service territory. The program consisted of upgrading or retiring assets such as poles, wire, transformers, and substations to a more modern construction standard, resulting in a more reliable and easier to restore system. NIPSCO completed the 4kV conversion project in 2021. A total of 19 4 kV circuits totaling approximately 33.8 circuit miles were upgraded to 12.5 kV, and seven 4 kV substations were retired.

Q27. Please identify investments NIPSCO is currently undertaking in its transmission and distribution system that are planned to be in-service by the end of the Forward Test Year (December 31, 2023).

A27. The investments NIPSCO is currently undertaking in its transmission and distribution system that are planned to be in-service by the end of the Forward Test Year are as follows:

(a) <u>138Kv Synchronous Condenser</u>. This project includes the installation of a new 138 kV Synchronous Condenser, which will replace the Unit 8 Synchronous Condenser conversion (completed in 2018). The Synchronous Condenser will have a rating of +360/-180 Megavolt Ampere Reactive Power (MVAR) and will be a long-term solution for short circuit and voltage support on the local 138 kV electrical system. This investment is needed to support NIPSCO's transition to renewable energy.

(b) LNG to Stillwell. This project was identified in connection with NIPSCO's integrated resource plan to prepare for the retirement of Schahfer. This project includes a 138 kV circuit upgrade with new monopole towers and larger current carrying conductor.

(c) Shoreline Substation. Michigan City is one of NIPSCO's oldest 138 kV substations, with drawings for the original facility dating back nearly 100 years, to the year 1926. The current substation configuration includes one breaker for every line and one breaker for the transfer bus. The failure of a breaker or fault on the transfer bus results in an outage at the entire substation. In the new bus configuration, three breakers are required for every two circuits. Utilizing this configuration, any circuit breaker can be isolated and removed for maintenance without interrupting supply of any of the other circuits. The breaker and a half scheme is very flexible and highly reliable. This bus configuration will improve system safety and performance by preventing errors tied to the existing complex bus configuration during switching operations and allow for ease of future maintenance activities. The substation will be relocated and completely rebuilt to current standards to increase safety, operability, and compliance. The scope of this project includes replacement of the remainder of the 138 kV breakers and their ancillary equipment and an entirely new relay house. This is an approved project under NIPSCO's current electric TDSIC Plan.

(d) Electric Control Center. A new electric control center is being constructed to improve communications and operations of the NIPSCO electric operations department. The project will co-locate Transmission Operations, Generation Operations, Distribution Operations, Operations Dispatch, Operation Planning, Compliance Training, Security Operations Center, and Operations Technology. Construction is expected to begin in late 2022 with most construction taking place through the end of 2023 and into 2024. This new facility will improve internal and external operations communication, coordination, and situational awareness. Other benefits include integrated transmission and distribution outage management and emergency response coordination. The new facility will be able to accommodate new technology systems, including Advanced Distribution Management Systems and Advanced Metering Infrastructure.

Q28. Are there any transmission facilities that are not included in NIPSCO's jurisdictional rate base in this case?

A28. Yes. NIPSCO owns and operates certain transmission facilities which are treated as non-jurisdictional assets as approved in Cause Nos. 44156-RTO-1, 13, and 19. These transmission facilities consist of two Multi Value Projects, four Targeted Market Efficiency Projects, and one Interregional Market Efficiency Project as defined by MISO and further described in the RTO proceedings listed. As these projects were granted non-jurisdictional treatment, they are excluded from jurisdictional rate base in this case.

Q29. In your opinion, are NIPSCO's jurisdictional transmission and distribution plant and equipment used and useful in the provision of electricity to NIPSCO's retail electric customers?

A29. Yes. NIPSCO's jurisdictional transmission and distribution plant and equipment are essential to the reliable transport and delivery of electricity from NIPSCO's generation fleet (or from other generators) to its retail customers to meet customers' needs for electric power.

Customer Service and Reliability[1]

Q30. Please summarize the reliability metrics associated with NIPSCO's transmission and distribution system since the 45159 Electric Rate Case.

A30. NIPSCO monitors three main metrics to evaluate the reliability of the transmission and distribution system: SAIFI, SAIDI and CAIDI (the "reliability metrics"). SAIFI is the System Average Interruption Frequency Index and represents the average number of times that a system customer experiences an outage during the year. SAIDI is the System Average Interruption Duration Index and represents the number of minutes a utility's average customer did not have power during the year. CAIDI is the Customer Average Interruption Duration Index and represents the average time of an outage during the year.

NIPSCO's reliability indices, SAIFI, SAIDI, and CAIDI, have increased since the 45159 Electric Rate Case. As shown in Figure 2 below, when

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[1] As noted above, additional information on NIPSCO's customer service and reliability metrics is available in its PMC Report filed on July 1, 2022, in Cause No. 44688.

looking at the reliability metrics from an all-inclusive perspective, NIPSCO has seen increases in SAIFI, SAIDI, and CAIDI. NIPSCO believes this is a result from the number of Major Event Days ("MED") it has experienced over the years. MED are primarily storms or severe weather events that are more destructive than typical storm events. Figure 3 below illustrates the number of MED in NIPSCO's service territory and the threshold that was used to identify major event days each year. As shown in Figure 3, NIPSCO has seen an increase in MED in recent years, due to stronger storm activity across the service territory. Furthermore, NIPSCO has seen an increased number of MED in the last 4 years, with two of the highest number of MED in 2019 and 2021. The increase in MED and associated restoration days in 2021 is the result of increased severe weather in 2021, with 10 MED, which is the highest in the past 10 years.

When looking at the reliability metrics, without MED, NIPSCO has held steady in regard to SAIFI, since the 45159 Electric Rate Case. This can be attributed to: (1) increasing NIPSCO's vegetation management funding in its distribution and transmission circuit program; (2) execution of the TDSIC plan providing system resiliency; and (3) NIPSCO's Outage

Investigation Program which targets outages that resulted in over 1,000 customers affected. NIPSCO expects to see additional improvement in SAIFI, as it continues investing in its vegetation circuit trimming and executing its current TDSIC plan, which includes hardening the system with new wood poles, replacing older vintage underground cable, and deploying additional distribution automation.

As far as SAIDI and CAIDI, without MED, NIPSCO has seen the metrics increasing since the 45159 Electric Rate Case. Even though NIPSCO owns five mobile substations to assist with construction activities, NIPSCO still has the need in many cases to tie circuits to adjacent substations or circuits during construction activities. Therefore, when an outage occurs on circuits that are tied, the number of customers impacted is increased. NIPSCO expects to see improvements in both SAIDI and CAIDI with the execution of its current TDSIC plan, which includes "Grid Modernization" investments, through which NIPSCO will provide value to its customers by reducing outage severity and duration, thereby improving the customer experience.

Figure 2. NIPSCO Reliability Metrics (Including MED)

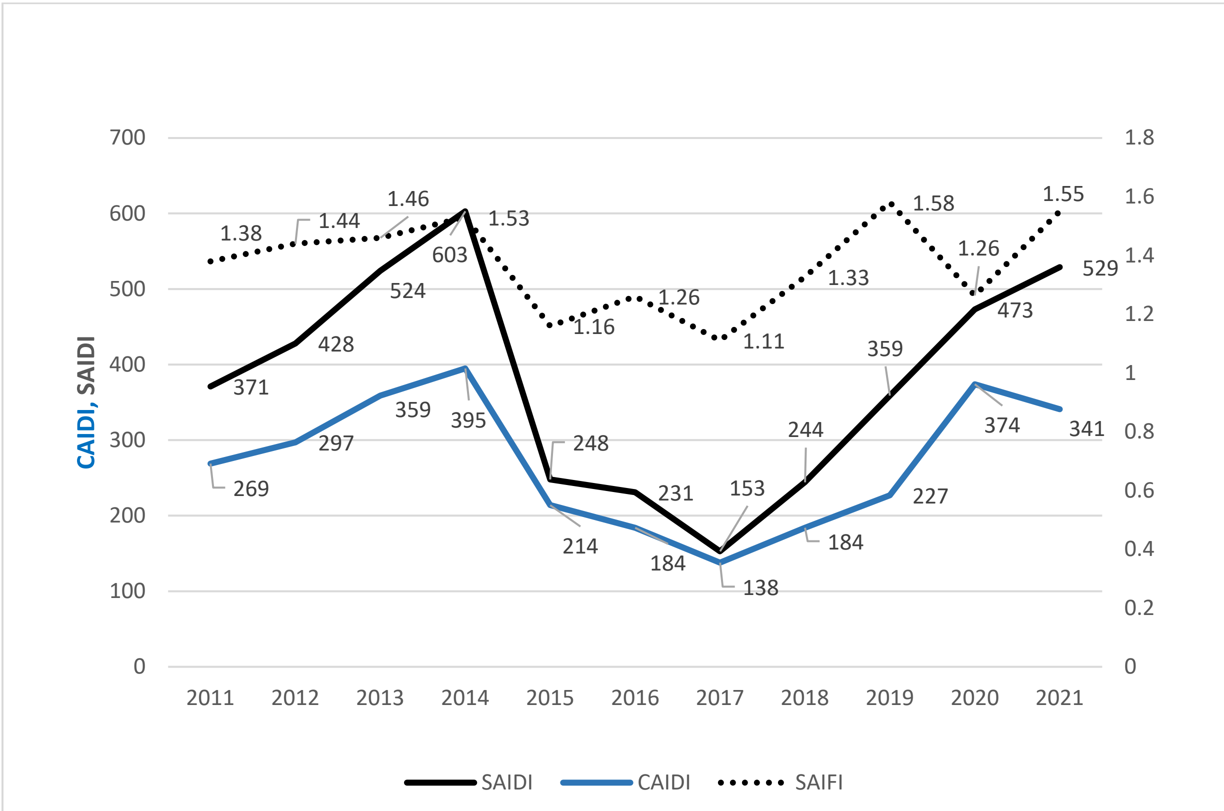
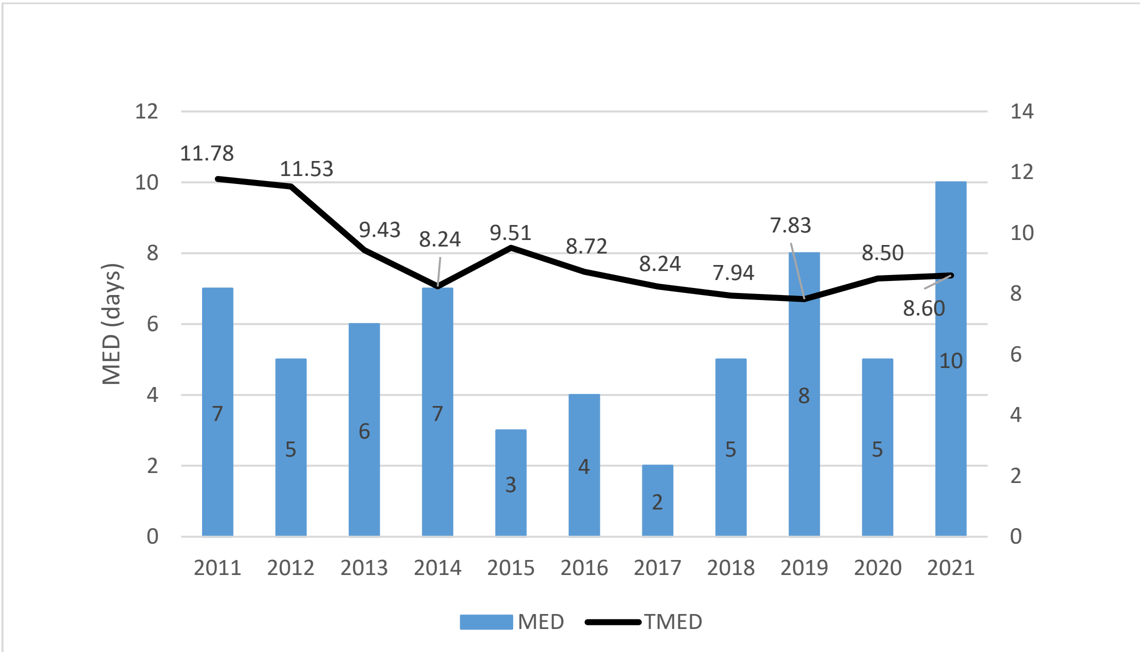


Figure 3. NIPSCO's Major Event Days Metrics



Q31. Are NIPSCO's transmission and distribution reliability metrics in line with industry standards?

A31. Yes. NIPSCO uses the Institute of Electrical and Electronics Engineers ("IEEE") Standard 1366-2012 when calculating the metrics for SAIFI, SAIDI, and CAIDI. Overall, NIPSCO has been holding steady when compared to its peers. <u>Figure 4</u> shows that NIPSCO's SAIFI has been lower (better) than the IEEE industry median for medium-sized utilities over the past 10 years. <u>Figure 5</u> shows that NIPSCO's SAIDI has been below or slightly above the

IEEE industry median for medium-sized utilities over the past 10 years.[2] NIPSCO saw an increase to SAIDI in 2021 because of a high number of severe weather days (27) impacting its customers. A severe weather day for NIPSCO is determined when 20% of the Threshold Major Event Day ("TMED") calculation for the year is met (TMED is referenced in Figure 3).

Finally, Figure 6 shows that NIPSCO's CAIDI has been above the IEEE industry median for medium-sized utilities over the past 10 years. Similarly, as in the case for SAIDI, NIPSCO also saw an increase to CAIDI in 2021 because of a high number of severe weather days (27) impacting its customers and workforce availability impacts from COVID-19 worker safety protocols.

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[2] IEEE Standard 1366-2012 Beta Method using a utility's daily SAIDI values for the past five reporting years.

Figure 4. SAIFI (excluding Major Events)

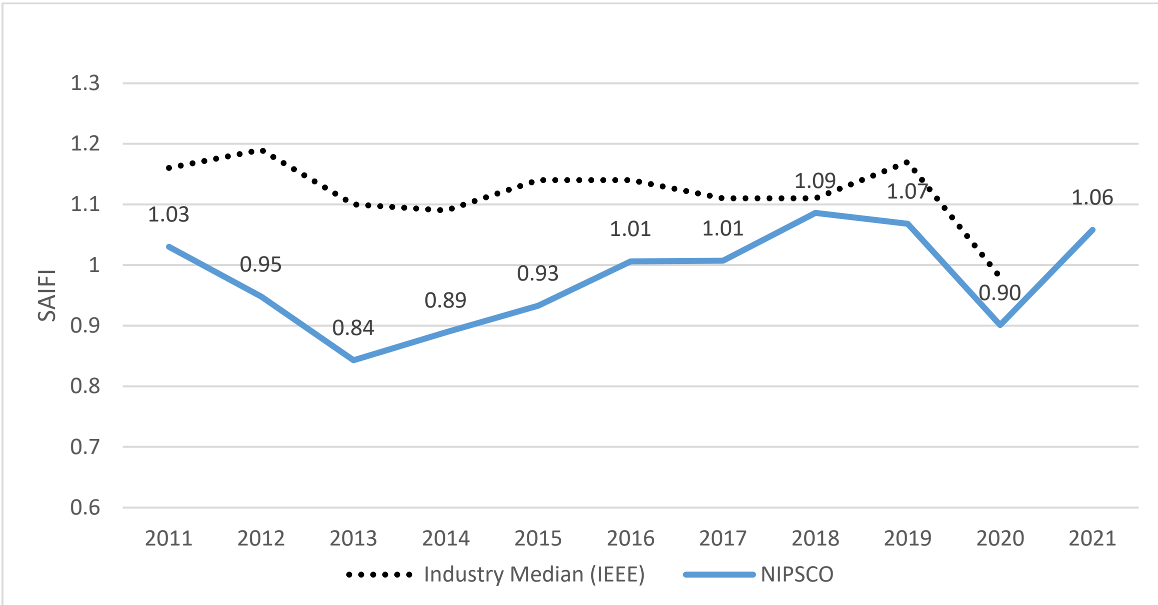


Figure 5. SAIDI (excluding Major Events)

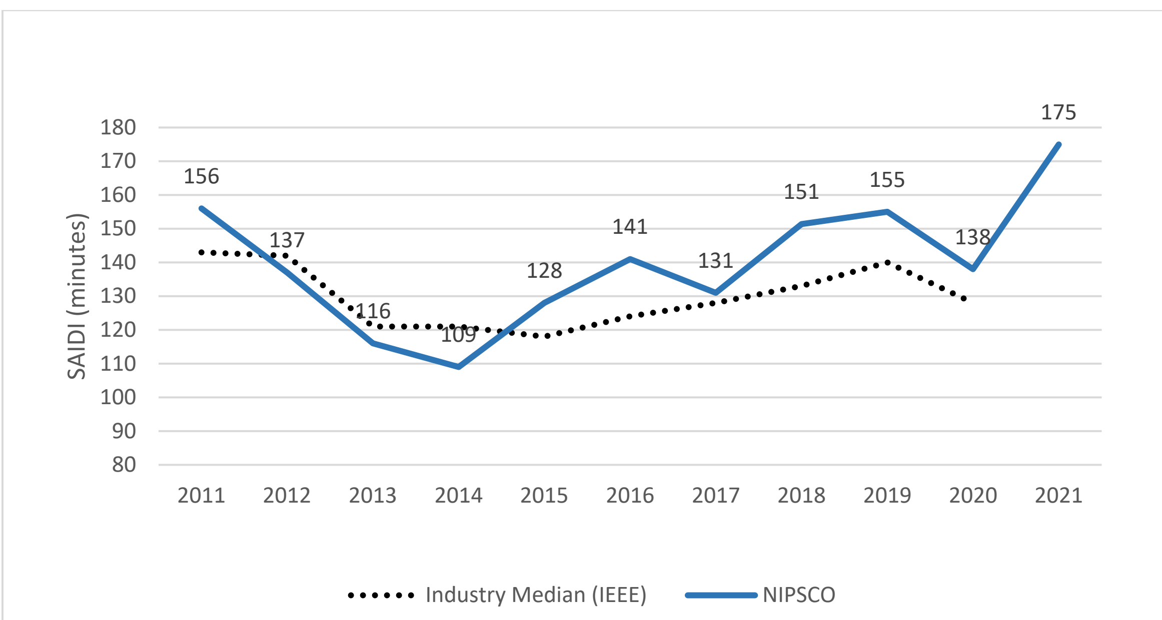
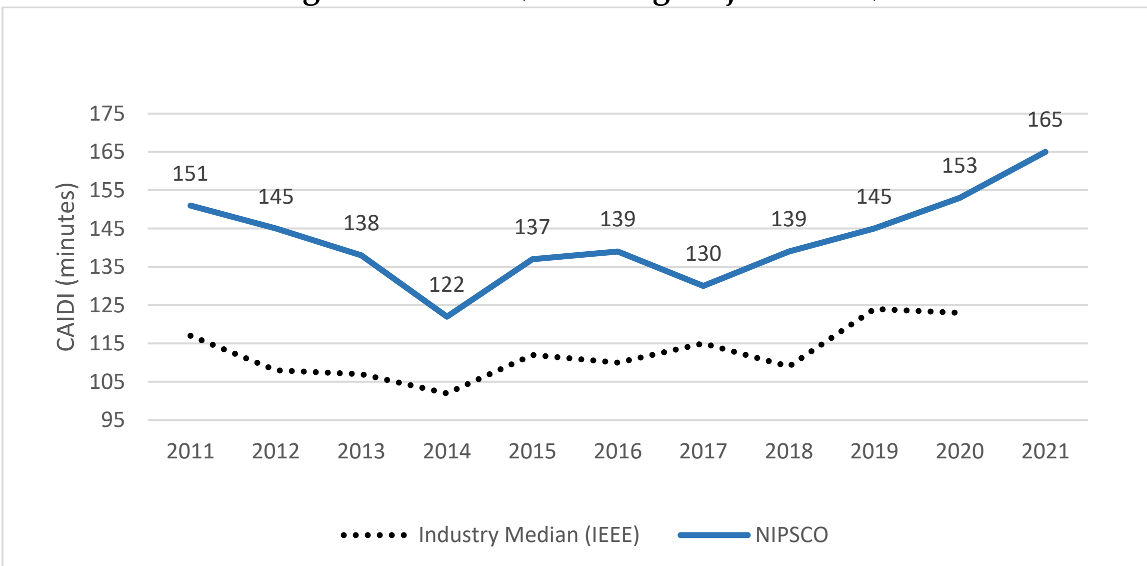


Figure 6. CAIDI (excluding Major Events)



Q32. What types of maintenance programs are in place at NIPSCO to ensure electric system reliability?

A32. NIPSCO has a comprehensive set of proactive substation, transmission, and distribution maintenance programs targeted at reliability. These include an active vegetation management program and capital investments aimed at enhancing system capabilities, improving reliability, and replacing aging infrastructure where needed. NIPSCO also continues to review and enhance its transmission system maintenance program procedures and record systems to improve reliability, reduce mis-operations, and ensure compliance with North American Electric Reliability Corporation standards.

NIPSCO is currently operating its wooden structure inspection program on a 10-year cycle. This program includes the treatment/life extension of poles meeting minimum strength requirements and replacement of those that do not meet those requirements. The pole program inspects approximately 30,000 wooden transmission and distribution poles per year and replaces a minimum of 1,200 poles on an annual basis. A similar program has been implemented for NIPSCO's steel structures, which includes the inspection, remediation, and coating of NIPSCO's steel lattice structures and monopoles. Currently this program operates on a 20-year cycle and includes structures both outside and inside of substations.

Other system reliability programs include the periodic inspections and maintenance of transmission lines and structures, substation equipment, protective relay systems, and distribution pad-mount transformers, pole-mounted reclosers, voltage regulators, switched capacitors, and other underground equipment. These programs also include the remedial work necessary to repair or replace minor plant items found to be deficient from inspection criteria.

Q33. How does NIPSCO's TDSIC plan address system reliability?

A33. One focus of NIPSCO's TDSIC plan is reducing system risk by addressing projects related to aging infrastructure. These projects focus on mitigating assets that have high likelihood of failure, as well as a high consequence of failure. By doing this, NIPSCO can prioritize those assets that will have the highest probability of failing that will also have the largest impact to NIPSCO's customers, as well as safety and environmental impacts.

A specific example of the reliability improvements NIPSCO's customers have experienced can be quantified through the execution of the Underground Cable Replacement program. This program focuses on 1970s and 1980s vintage unjacketed cable, which accounts for 90% of the underground faults each year. NIPSCO focused its replacement on the impact of a failure and the frequency of failures. With this, over the last 10 years, NIPSCO has decreased the number of customers affected each year by an underground fault from over 10,000 to under 8,000, a 20% improvement. Execution of this program has also decreased the number of underground faults on NIPSCO's system from over 300 to just above 200 each year; a 33% improvement.

Q34. In addition to the maintenance programs described above, what other actions has NIPSCO undertaken to maintain and/or improve customer service and reliability?

A34. On an annual basis, NIPSCO reviews and, if needed, makes adjustments to its Electric Emergency Response Plan ("EERP"). The EERP is a coordinated and comprehensive response plan for rapid restoration of electric service in the event of severe weather, or other system emergencies, by ensuring that all required corporate resources are utilized in the most effective manner.

In addition, NIPSCO continues its formal Outage Investigation Program. This Program reviews any outages that impact more than 1,000 customers, result in a pole fire or similar safety-related event, or have an outage cause code of "unknown." The findings are reported out through the organization. Lineman, Substation Electricians, Supervisors, Dispatchers, and Engineers all benefit from these report findings by applying these lessons learned to their designs, materials, and construction methods to improve reliability. This Program also reviews and updates the outage cause codes to identify the true outage root cause. Doing so allows NIPSCO to perform analytics more accurately on its outage causes and make improved decisions on materials, designs, construction methods, and maintenance techniques. This Program averages 110 investigations per year and is made up of the most impactful outages to NIPSCO's customers.

NIPSCO maintains a Line & Substation voltage regulator maintenance replacement program to reduce service failures leading to enhanced customer reliability. Newer design regulators incorporate enhanced tap changers that reduce contact wear and thus premature failure. Microprocessor based controls have been more reliable than analog controls, with the added benefit of enhanced customer voltage profile.

NIPSCO continues to perform its Circuit Performance Improvement Program to better improve electric system reliability. The Program includes calculating the SAIFI, SAIDI, and CAIDI, and Customer Duration Hours annually for each circuit and determining an overall performance value for each circuit. The circuits with the worst performance values are then assessed and recommendations for improvement are developed. The Program includes identifying all taps that have experienced multiple outages in the previous year and developing recommendations for improvement. Recommendations for improvement for the Circuit Performance Improvement Program include targeted tree trimming, replacement of equipment prone to failure, replacement of equipment that is in poor condition, an analysis of fuse coordination and loading, and installing additional sectionalizing devices (Cut-Outs, Triple-Shots, Reclosers, Switches, etc.), where appropriate, to minimize the impacts of outages and the number of customers affected per outage.

NIPSCO has commenced rollout of a modern distribution automation ("DA") system to replace NIPSCO's current aged DA system. This system will help to sectionalize NIPSCO's customers down to 500 count sections, which reduces the number of customers affected by a system interruption. It will also help pinpoint the cause of the interruption, further reducing the time needed to patrol the affected circuit to find the defect.

NIPSCO has also completed its investment in an Enhanced Outage Management System ("EOMS") to improve customer experience by providing for faster restoration and more accurate communication of estimated time of restoration during planned and unplanned outages. Overall, the EOMS will serve as the foundational platform to drive dependable, predictable, timely service and emergency response.

Finally, to enhance customer experience, NIPSCO improved its mobile user application to show the outage cause when NIPSCO has updated the estimated time of restoration ("ETR"). All electric customers that have supplied NIPSCO with an email address were auto-enrolled to receive power outage email alerts. NIPSCO also allows customers to enroll themselves to receive Account Alert notifications via text and/or voice message for unplanned electrical outages and ETR notifications. This information allows NIPSCO to inform customers on the duration of the outage so customers can plan their day accordingly.

Q35. Has NIPSCO seen reductions in tree-related outages events?

A35. Except for 2021, NIPSCO has seen an overall reduction of Tree Related Outages ("TROs") since 2016. As shown in Table 4 below, 2021 had a high number of localized weather-related events. When comparing the 3-year period 2016 to 2018 and 2019 to 2021 in Table 5, NIPSCO's average tree related outages improved from 3,637 (2016 to 2018) to 3,060 (2019 to 2021). This improvement is encouraging, considering NIPSCO has experienced more weather event days from 2019 to 2021 compared to 2016 to 2018 and confirms NIPSCO is targeting the correct circuits that is causing the most customer outages. However, NIPSCO is moving to a more proactive approach that focuses on its distribution and sub-transmission circuits.

Table 4

Tree Related Outages (Excluding Major Events)		
	Outages	Severe Days
2016 Tree Outages	3705	15
2017 Tree Outages	3610	16
2018 Tree Outages	3595	20
2019 Tree Outages	3056	29
2020 Tree Outages	2892	15
2021 Tree Outages	3233	27

Table 5

3-Year Period	Avg. Tree Outages (Excluding Major Events)	Avg. Severe Days	Avg. MED
2016 – 2018	3,637	17	3.6
2019 – 2021	3,060	23.6	7.6

Q36. What vegetation management cycle is NIPSCO currently on for its distribution and sub-transmission circuit program?

A36. On average for the last three years, NIPSCO has trimmed approximately 750 circuit miles per year. Assuming this pace continues, NIPSCO would trim each mile of circuit once every 11 years. However, NIPSCO's experience is, on average, trees grow back into the lines within a 5-year period. In order to trim or clear each of its distribution and sub-transmission circuits every 5 years, a significant number of additional crews would need to be utilized and would cover about 1,600 miles per year.

Q37. What is the biggest challenge NIPSCO faces to be able trim each circuit every 5 years?

A37. Public and employee safety is NIPSCO's utmost priority when performing work. Consequently, NIPSCO only partners with contractors who specialize in this kind of work and have proven experience in tree clearing around energized lines. NIPSCO has been working with its labor contractors to develop a plan to ramp up staffing in a prudent and responsible way to recruit, train, and retain talent to work on energized lines. In fact, NIPSCO has begun onboarding crews starting in 2022 and will continue this steady approach until meeting the staffing requirements, which is currently targeted to conclude in the last quarter of 2023. Getting to the place where each circuit mile is cleared every five years would require additional crews and additional expenditures, especially with the tight labor market and cost increases, which are discussed further below.

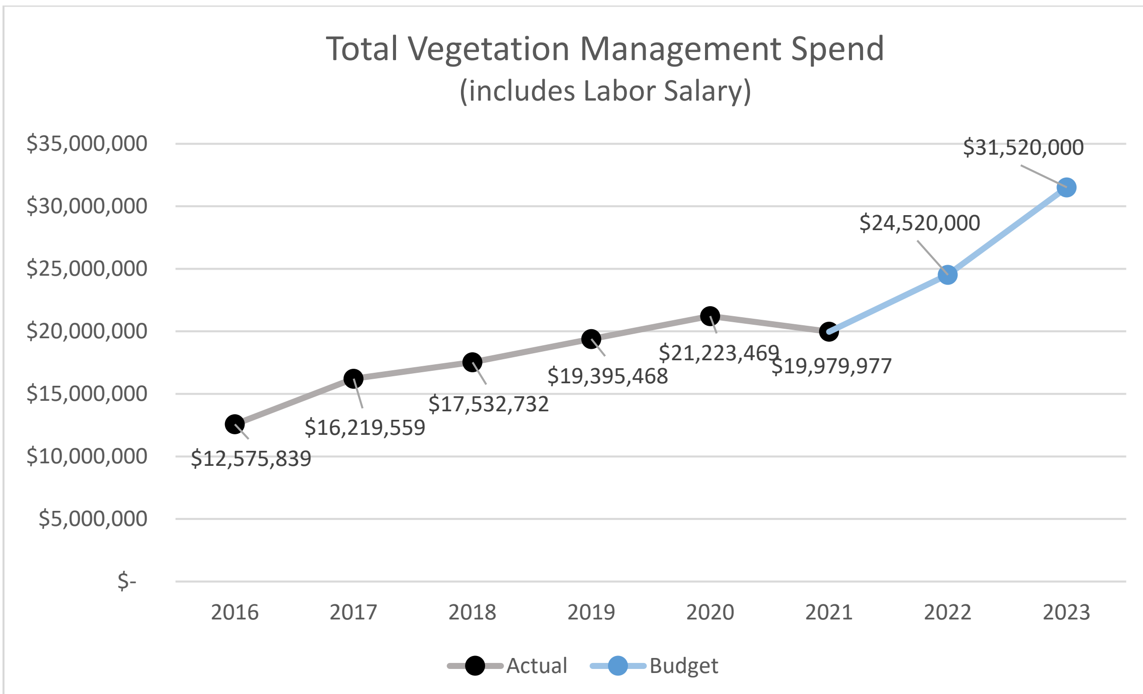
Q38. How are customer service and reliability goals incorporated into NIPSCO's planning process?

A38. NIPSCO prepares an annual operating plan to outline long term and near-term operational goals, plans, and performance targets. Key elements of this plan include a focus on service and reliability improvements. Performance targets are established that represent stretch levels of continuous improvement and initiatives are then outlined to achieve the performance targets. These performance targets and initiatives are then cascaded throughout the organization in an aligned and increasingly more specific manner, becoming a core part of the annual performance management process. NIPSCO's performance initiatives are directly tied to reliability metrics (SAIFI, SAIDI, and CAIDI), safety metrics (OSHA recordables, DART, and PVCs), and staying within operation budget, and targets for these metrics are included in performance expectations.

Q39. Please describe NIPSCO's Vegetation Management Program.

A39. To improve reliability, as shown in <u>Figure 7</u> below, NIPSCO has steadily increased funding for its vegetation management program to specifically focus on trimming more circuit miles on distribution and sub-transmission circuits. NIPSCO has used the majority of the budget increase to clear circuits that have the highest tree-related outages.

Figure 7. Total Vegetation Management Spend



Over the years, the line mile cost has become more expensive. NIPSCO has experienced increases in the cost of performing line clearance tree trimming from its preferred vendors. Tight labor markets, competition for labor of neighboring utilities, and increases in fuel and equipment costs, have all led to increasing the cost to perform the work.

In 2017, NIPSCO Vegetation Management held a category specific sourcing event with vendors to secure pricing for multi-year contracts. The sourcing strategy performed in 2017 and renewed in 2021 fundamentally changed the way NIPSCO performs line clearance activity. The event moved NIPSCO to a unit-based model with a multi-year commitment from the preferred partners to lock prices for the term of the contract with a commitment from NIPSCO for steady and stable work during the contract term. This partnership has assisted the partners to secure resources to assist in controlling increases in costs.

Between 2021 and 2022, the cost for equipment has also increased. All categories of equipment saw an increase beyond the annualized inflation rate. Similarly, labor has increased for some of the individual labor classes. The increase in labor and equipment are primarily driven by the increased demand for resources across the industry and a tightening of the labor and equipment resources. According to NIPSCO contractors, the market constraints are due to the low unemployment rate, and other utilities increasing their demand for vegetation contractors.

Due to increases in contractor costs, NIPSCO's 2023 budget funding of approximately $30 million will provide for the completion of approximately 1,200 miles of line, which is slightly better than a 7-year cycle. The market adjustment increases will allow NIPSCO to continue to take steps to improve customer reliability and experience by reducing vegetation related outages.

<u>Pro-Forma Expense Adjustments</u>

Q40. Please describe Adjustment OM 2A-23R for Generation Maintenance Activity expenses shown on <u>Petitioner's Exhibit No. 3</u>, Attachment 3-C-S2, OM 2A.

A40. Adjustment OM 2A-23R is a rate making adjustment increasing the Generation Base Maintenance expense by $1,629,147 to reflect an historical (2019-2021) 3-year average. If this adjustment is not included, the Forward Test Year electric operating expenses will be understated. Details of this adjustment can be found in <u>Petitioner's Confidential Exhibit No. 22-S2</u>, Workpaper OM 2A.

Q41. Please describe Adjustments OM 2B-23R for Planned Outages expenses shown on <u>Petitioner's Exhibit No. 3</u>, Attachment 3-C-S2, OM 2B.

A41. Adjustment OM 2B-23R is a rate making adjustment decreasing the Planned Outages expense by $3,207,062 to reflect an historical (2019-2021)

3-year average. The planned outage schedule varies by year, and the workplan for each generating station details the projected expenditure amount by station, unit, and major component. If this adjustment is not included, the Forward Test Year electric operating expenses will be overstated. Details of these adjustments can be found in Petitioner's Confidential Exhibit No. 22-S2, Workpaper OM 2B.

Q42. Please describe Adjustments OM 2C-23R for Forced Outages expenses shown on Petitioner's Exhibit No. 3, Attachment 3-C-S2, OM 2C.

A42. Adjustment OM 2C-23R is a rate making adjustment increasing the Forced Outage expense by $1,053,877 to remove Schahfer Unit 14 and 15 and reflect an historical (2019-2021) 3-year average. If this adjustment is not included, the Forward Test Year electric operating expenses will be understated. Details of this adjustment can be found in Petitioner's Confidential Exhibit No. 22-S2, Workpaper OM 2C.

Q43. Please describe Adjustments OM 2D for Variable Chemicals expenses shown on Petitioner's Exhibit No. 3, Attachment 3-C-S2, OM 2D.

A43. Adjustment OM 2D-21 is a normalization adjustment decreasing the Historic Base Year expense by $897,199 to remove variable chemicals associated with Schahfer Unit 14 and 15. If this adjustment is not included, the Historic Base Year electric operating expenses will be overstated. Details of this adjustment can be found in Petitioner's Confidential Exhibit No. 22-S2, Workpaper OM 2D.

Q44. Please describe Adjustments OM 2E for Nontrackable Fuel Handling expenses shown on Petitioner's Exhibit No. 3, Attachment 3-C-S2, OM 2E.

A44. Adjustment OM 2E-21 is a normalization adjustment decreasing the Historic Base Year expense by $7,923,431 to remove nontrackable fuel handling expense associated with Schahfer Unit 14 and 15. If this adjustment is not included, the Historic Base Year electric operating expenses will be overstated. Details of this adjustment can be found in Petitioner's Confidential Exhibit No. 22-S2, Workpaper OM 2E.

Q45. Please describe Adjustments OM 2G for Line Locates expenses shown on Petitioner's Exhibit No. 3, Attachment 3-C-S2, OM 2G.

A45. Adjustment OM 2G is a rate making adjustment increasing the Line Locates operating expenses by $1,602,370. Overall, NIPSCO has experienced increases in the volume of line locate tickets year-over-year. The proposed adjustment reflects an 11.75% ticket volume increase, based on a 4-year average. The main driver of the volume is attributed to increases in public marketing and awareness regarding calling 811 for a locate ticket and increases in fiber and infrastructure investments occurring across the service territory.

The pro forma adjustment also reflects incremental cost per ticket increases, which include labor rate increases to retain talent and price increases to perform audits at a 10% rate (up from 5% in 2021) to ensure better quality of locates. If this adjustment is not included, the Forward Test Year electric operating expenses will be understated. Details of this adjustment can be found in Petitioner's Confidential Exhibit No. 22-S2, Workpaper OM 2G.

Q46. Please describe Adjustments OM 2I for Non-jurisdictional expenses shown on Petitioner's Exhibit No. 3, Attachment 3-C-S2, OM 2I.

A46. Adjustment OM 2E-23 is a rate making adjustment decreasing the Non-jurisdictional expense by $474,915 to remove non-jurisdictional expense based on the monthly average for January to May 2022 actuals. If this adjustment is not included, the Forward Test Year electric operating expenses will be overstated. Details of this adjustment can be found in Petitioner's Confidential Exhibit No. 22-S2, Workpaper OM 2I.

Q47. Does this conclude your prefiled direct testimony?

A47. Yes.