ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF PETITIONER'S 7-YEAR ELECTRIC TDSIC PLAN FOR ELIGIBLE TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS, PURSUANT TO IND. CODE § 8-1-39-10(a), FOR AUTHORITY TO DEFER COSTS FOR FUTURE RECOVERY, AND APPROVING INCLUSION OF NIPSCO'S TDSIC PLAN PROJECTS IN ITS RATE BASE IN ITS NEXT GENERAL RATE PROCEEDING PURSUANT TO IND. CODE § 8-1-2-23.	)	CAUSE NO. 44733 APPROVED: JUL 12 2016

ORDER OF THE COMMISSION

Presiding Officers:
James F. Huston, Commissioner
Aaron A. Schmoll, Senior Administrative Law Judge

On December 31, 2015, Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") petitioned the Indiana Utility Regulatory Commission ("Commission") for approval of Petitioner's 7-year plan for eligible transmission, distribution and storage system improvements ("7-Year Electric Plan" or "Plan"), pursuant to Ind. Code § 8-1-39-10(a). Citizens Action Coalition of Indiana, Inc. ("CAC"), Indiana Municipal Utilities Group ("Municipal Utilities"), LaPorte County Board of Commissioners ("LaPorte"), NIPSCO Industrial Group ("Industrial Group") and United States Steel Corporation ("U.S. Steel"), filed petitions to intervene, all of which were subsequently granted.

On March 24, 2016, NIPSCO, the Indiana Office of Utility Consumer Counselor ("OUCC"), Industrial Group, LaPorte, Municipal Utilities and U.S. Steel (the "Settling Parties") filed a 7-Year Plan and Transmission, Distribution and Storage System Improvement Charge ("TDSIC") Settlement Agreement (the "Settlement"). On April 5, 2016, NIPSCO, the OUCC, Industrial Group, LaPorte and Municipal Utilities prefiled testimony supporting the Settlement.

On May 4, 2016, the Commission conducted an evidentiary hearing starting at 9:30 a.m., in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, the prefiled evidence of NIPSCO, the OUCC, Industrial Group, LaPorte and Municipal Utilities as well as NIPSCO's responses to the April 29, 2016 docket entry were admitted into the record without objection. CAC's Cross Exhibits 1 and 2 were also admitted into the record without objection and CAC's request for administrative notice was granted. No members of the general public appeared or participated at the hearing.

Having considered the evidence and being duly advised, the Commission now finds:

1. **<u>Notice and Jurisdiction</u>**. Due, legal, and timely notice of the hearing in this

Cause was given as required by law. Petitioner is a "public utility" within the meaning of Ind. Code §§ 8-1-39-4 and 8-1-2-1 and is an "energy utility" within the meaning of Ind. Code § 8-1-2.5-2 and is subject to the jurisdiction of this Commission in the manner and to the extent provided by the Public Service Commission Act, as amended, and other pertinent laws of the State of Indiana. Accordingly, the Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. <u>Petitioner's Characteristics</u>. Petitioner is a public utility organized and existing under the laws of the State of Indiana and having its principal office at 801 East 86th Avenue, Merrillville, Indiana. Petitioner is engaged in rendering electric and gas public utility service in the State of Indiana and owns, operates, manages and controls, among other things, plant and equipment within the State of Indiana used for the generation, transmission, distribution and furnishing of such service to the public.

3. <u>Requested Relief</u>. In accordance with Ind. Code § 8-1-39-10(a), Petitioner requested Commission approval of its 7-Year Electric Plan, as follows:

(a) a finding that the projects contained in the 7-Year Electric Plan are "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code § 8-1-39-2;

(b) a finding of the best estimate of the cost of the eligible improvements included in the Plan;

(c) a determination that the public convenience and necessity require or will require the eligible improvements included in the Plan;

(d) a determination that the estimated costs of the eligible improvements included in the Plan are justified by incremental benefits attributable to the Plan;

(e) a determination that the 7-Year Electric Plan is reasonable and should be approved, and designating the eligible transmission, distribution and storage system improvements included in the Plan as eligible for Transmission, Distribution and Storage System Improvement Charge ("TDSIC") treatment;

(f) authority to defer costs associated with the 7-Year Electric Plan that are incurred prior to and subsequent to the issuance of an Order in this proceeding until such amounts are recovered through rates;

(g) approval of including of Petitioner's 7-Year Electric Plan projects in its rate base in its next general rate proceeding; and

(h) approval of Petitioner's proposed process for updating the 7-Year Electric Plan in future TDSIC adjustment proceedings.

4. <u>Petitioner's Case-in-Chief Evidence</u>.

A. <u>Direct Testimony of Timothy R. Caister</u>. Mr. Caister, Director of

Regulatory Policy for NIPSCO, provided testimony to (a) give an overview of the relief requested in this proceeding, (b) explain why the components of NIPSCO's 7-Year Electric Plan are eligible transmission, distribution, or storage system improvements, (c) support the conclusion that NIPSCO has provided best estimates of the cost of its 7-Year Electric Plan and explain NIPSCO's proposed process for updating the Plan going forward, (d) explain why the public convenience and necessity require or will require the eligible improvements included in the Plan, (e) explain why the estimated costs of the eligible improvements included in NIPSCO's 7-Year Electric Plan are justified by incremental benefits attributable to the Plan, (f) explain NIPSCO's proposed Streetlight Program, (g) explain NIPSCO's approach to inclusion of eligible economic development projects in the Plan, (h) detail the process NIPSCO employed and intends to employ to update its stakeholders prior to subsequent TDSIC filings, and (i) confirm NIPSCO's intent to file a general rate case consistent with the provisions of the TDSIC Statute.

Mr. Caister testified NIPSCO has increased the level of detail provided in support of its 7-Year Electric Plan to ensure that an appropriate level of detail is provided to allow the Commission and stakeholders to evaluate the costs and benefits of the proposed projects. He explained that going forward and prior to the start of a new Plan year, NIPSCO will define the detailed project scopes and updated unit estimates for at least the next plan year, with the exception of Circuit Performance Improvement projects, which are planned at the beginning of the calendar year. He stated that Appendix 5 of the Plan provides the unit cost tables and methodology by project type for single unit projects in years 2018-2022 and for multiple unit projects for all years of the Plan. In addition, the Plan does not include any O&M projects.

Mr. Caister testified how NIPSCO addressed the findings in the Commission's December 16, 2015 Order in Consolidated Cause Nos. 44370 and 44371 (the "Remand Order"). He explained the Commission found that the level of detail provided in support of the Settlement Agreement approved in the Remand Order was consistent with the obligation to "submit detail at a reasonably defined individual improvement level" with respect to projects involving NIPSCO's major transmission and distribution assets.[1] He testified NIPSCO has provided the same level of detail in this proceeding and, more importantly, NIPSCO has substantially increased the level of detail presented in its 7-Year Electric Plan with respect to the aging infrastructure components of its 7-Year Electric Plan to provide detail at the individual improvement level.

Mr. Caister testified that while it does not seem most effective to incorporate the thousands of Aging Infrastructure assets into the same risk analysis with the major transmission and distribution assets, NIPSCO recognized the need to provide its stakeholders and the Commission with detailed information about the individual improvements proposed and the processes used to identify them. As a result, with the exception of the circuit performance improvement project, NIPSCO has developed asset registers for each asset category included in its aging infrastructure program. He noted that, additionally NIPSCO requested that Black & Veatch evaluate the processes used to identify and prioritize assets within those categories to verify that its approach was sound.

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[1] Specifically, the Commission found that projects identified in Remand Exhibit TAD-R1 included a sufficient level of detail. Remand Order at 12.

Mr. Caister testified NIPSCO's 7-Year Electric Plan is focused on transmission and distribution investments made for safety, reliability, and system modernization. The Plan also makes provision for appropriate economic development projects in the future, although none are proposed at this time. NIPSCO's 7-Year Electric Plan includes necessary investments that enable NIPSCO to continue providing safe, reliable electric service to its customers into the future. The Plan is comprised of two main segments: (1) investments that target replacement of aging assets (Aging Infrastructure) and (2) investments intended to maintain the capability of NIPSCO's electric system to deliver power to customers when they need it (System Deliverability). In developing its Plan, NIPSCO considered the need to maintain a safe and reliable system.

Mr. Caister testified that all investments included in the Plan are new or replacement electric transmission or distribution utility projects that (1) NIPSCO is undertaking or will undertake for the purposes of safety, reliability, system modernization, or economic development; and (2) were not included in NIPSCO's rate base in its most recent general rate case in which an order was issued in Cause No. 43969 nor are they included in NIPSCO's rate base in its current general rate case currently pending before the Commission in Cause No. 44688.

Mr. Caister testified all investments included in the Plan meet the requirements necessary to be designated as eligible transmission, distribution, and storage system improvements as defined in Ind. Code § 8-1-39-2. He stated that NIPSCO has provided the best estimate of the cost of the eligible improvements included in the Plan, the public convenience and necessity require or will require the eligible improvements included in the Plan, the Economic Impact Report provides the estimated economic impacts of NIPSCO's planned TDSIC expenditures for the State of Indiana, as well as the United States and demonstrates the estimated costs of the eligible improvements included in the Plan are justified by incremental benefits attributable to the Plan. He testified for all of these reasons the Plan is reasonable and NIPSCO requests the Commission to approve the Plan and designate the eligible transmission, distribution and storage system improvements included in the Plan as eligible for TDSIC treatment in accordance with Indiana Code Ch. 8-1-39.

Mr. Caister testified NIPSCO intends to update its 7-Year Electric Plan as required by the TDSIC Statute with each adjustment filing. In each of its Plan Updates, NIPSCO proposes to update the anticipated costs and annual spending for the 7-Year Electric Plan as well as costs for the economic development projects, if any. As part of each tracker filing, NIPSCO will update its 7-Year Electric Plan, including updates to the asset registers (including the municipalities included in the streetlights replacement program), if appropriate, as well as the cost estimates. Based on industry standards and Company needs, NIPSCO will continually refresh both the risk model as well as the analysis associated with deliverability and condition based projects. Prior to the start of a new Plan year, NIPSCO will define the detailed project scopes and updated unit estimates for at least the next plan year, with the exception of Circuit Performance Improvement projects, which are planned at the beginning of the calendar year. For Circuit Performance Improvement projects, NIPSCO will provide updates to the cost estimates for these in the first update filing following selection in the beginning of the applicable calendar year. In updating the Plan, NIPSCO will continue to refresh the prioritization and asset registers as new information becomes available. As the factors driving the analyses change, the risk profile of

NIPSCO's system will also change, which will require adjustments to the equipment ranking. He testified that to the extent the Plan Update includes a major modification, NIPSCO proposes to work with the parties to establish a subdocket to allow for additional time to review that request. NIPSCO recognizes that major updates to the plan may require additional discussion beyond what occurs as part of a 90-day tracker filing.

Mr. Caister testified the eligible improvements included in the 7-Year Electric Plan will serve the public convenience and necessity in various ways. First, NIPSCO's 7-Year Electric Plan is largely a replacement plan. The equipment that is in service today is used and useful in safely and reliably serving NIPSCO's customers with electric service. However, in order to continue serving NIPSCO's customers safely and reliably, the public convenience and necessity require that the assets identified in the 7-Year Electric Plan be replaced. The public's reliance on electricity is linked directly with quality of life, economic enhancement and overall public safety. NIPSCO takes its role seriously in serving its customers safely and reliably, and this includes protecting customers and employees from potential injury, property damage and sustained electrical outages. Second, NIPSCO seeks relief within the requirements provided by the General Assembly in Ind. Code Ch. 8-1-39. NIPSCO's 7-Year Electric Plan follows the requirements of the statute and achieves the legislative intent of making new and replacement transmission and distribution investments for the purposes of safety, reliability, system modernization and economic development. This is consistent with public policy and serves the public interest. Third, the eligible investments are essential in protecting the integrity, safety, and reliable operation of the system—not only for NIPSCO's customers, but also for the bulk electric system as a whole. These investments provide for the public convenience and necessity at a much broader level than just NIPSCO's service territory by reaching not only its customers but also all utilities and customers in the Eastern Interconnection. NIPSCO must do its part to help secure its portion of the bulk electric system. Customers also benefit through improved functionality and modernization of the grid. For all these reasons as well as those stated by Mr. Atkins, approval of the 7-Year Electric Plan is required and will be required for the public convenience and necessity.

Mr. Caister testified it is essential in considering the incremental benefit of NIPSCO's 7-Year Electric Plan to recognize that continued safe, reliable service from the investments in the Plan has been compared against the service deterioration that would occur if these investments were not made. In addition, NIPSCO's 7-Year Electric Plan creates efficiencies where possible by considering the system as a whole over the 7-year period and bundling replacements as appropriate for cost effectiveness.

Mr. Caister testified NIPSCO retained Black & Veatch to perform an analysis of the economic impact of NIPSCO's 7-Year Electric Plan. In summary, based on the investment level in NIPSCO's 7-Year Electric Plan, the Plan will support the equivalent of roughly 1,338 full-time jobs per year in and around NIPSCO's service territory over the 7-years of the Plan.[2] He noted there are three categories of jobs: (1) direct jobs, estimated to average 763 per year, are those directly related to the capital expenditures; (2) indirect jobs, estimated to average 130 per

[2] The report notes that 9,363 jobs will be directly attributable to the Plan. Those 9,363 jobs divided by 7 years yields roughly 1,338 jobs per year that would last over the seven years of the Plan.

year, are those caused by the purchase of inputs by third parties that are buying goods or services in order to provide the direct inputs; and (3) induced jobs, estimated to average 444 per year, arising from the spending of wages earned by those direct or indirect jobs. He stated that some of the direct jobs will result in additional NIPSCO staffing, while some will be through third parties. He noted that the exact number of jobs that are added at NIPSCO versus use of third parties is unknown at this time. He stated that additionally, outside of Indiana, the Plan will also support the equivalent of approximately 922 full-time jobs per year over the 7-years of the Plan.

Mr. Caister summarized the municipal streetlighting program that was approved in the Commission's February 17, 2014 Order in Cause No. 44370. He stated that in Cause No. 44370, the Indiana Municipal Utilities Group ("IMUG") proposed using part of NIPSCO's proposed economic development budget for a municipal streetlighting project to replace outdated, poorly illuminating, high-pressure sodium streetlighting with bright, light-emitting diode ("LED") lights in the commercial and business areas of municipalities. The Commission approved IMUG's proposal and noted that it was a limited exception to NIPSCO's proposed criteria for economic development projects. The Commission found that the public interest is served by NIPSCO working collaboratively with all interested municipalities (not just the municipalities comprising IMUG) in its service territory to replace company-owned light fixtures with more efficient LED lighting fixtures, and it directed NIPSCO to fund this program from a portion of its $10 million annual economic development budget. The Commission ordered NIPSCO to devise and implement a competitive process in order to select which interested municipalities receive these investments, based solely on the merits of their proposals.

Mr. Caister indicated that in collaboration with interested communities, NIPSCO representatives have been evaluating the fixtures available in the industry and have completed trials in three locations. NIPSCO's team worked with a number of different vendors, including visiting their facilities, in order to narrow the choices of potential fixtures. As the pilot progressed, NIPSCO worked with IMUG's expert, Dr. Robert Kramer of Purdue University-Calumet, to assure that the best information possible was collected. This included photometric testing of the trial fixtures and gathering input from customers near the trial locations as well as community leaders. NIPSCO issued an LED streetlighting standard in mid-2015, which includes light wattages, patterns, and approved manufacturers. In NIPSCO's rate case currently pending in Cause No. 44688, NIPSCO is requesting approval to add LED lighting to its Rate 650 - Streetlighting tariff for both Company- and customer-owned streetlights. He explained that a cross-functional team developed a request for information ("RFI") as well as a communications plan for providing information to the municipalities regarding the availability of this program. NIPSCO issued the RFI on June 15, 2015, with communications occurring before and after the RFI was made available. The goal of the RFI was to determine what cities and towns are interested in participating in the project, the number of NIPSCO lights that will need to be switched out in each municipality and the municipality's preferred year for the project. This allowed NIPSCO to assess the interest in the project and to make the appropriate allocation of resources. NIPSCO utilized a scoring matrix to set the priority of the projects. NIPSCO plans to issue an RFI each year to allow additional communities to indicate interest and will update the schedule for subsequent years based on interest.

Mr. Caister testified that 40 communities responded to the RFI, with more than 24,000 (out of approximately 42,000) Company-owned lights requested to be upgraded. NIPSCO used the weighted analysis, which included community investment, projected start date, quality of lights, etc. to determine the preliminary schedule. NIPSCO used this information to put together a replacement plan for the seven years of the Plan. This replacement plan allows NIPSCO to replace all of the lights in these communities, as well as the estimated 18,000 lights in the balance of NIPSCO's electric service territory. Appendix 6 of the Plan provides the Register of Streetlights by Municipality to be replaced over the course of the Plan. It is important to note that while NIPSCO anticipates replacing all of its Company-owned streetlights over the duration of the Plan, the actual municipalities where replacements take place in a given year may change due to community interest, the availability of labor, or other factors. He stated that as with other projects, NIPSCO will continue to update the Register of Streetlights by Municipality (Appendix 6) as needed.

Mr. Caister testified that NIPSCO anticipates a ramp up of installations beginning in mid-2016, with engineering beginning earlier in the year, and plans to replace approximately 4,500 streetlights in 2016. For the remaining six years of the Plan, NIPSCO anticipates an installation rate of an average of 6,250 lights per year.

Mr. Caister testified that since NIPSCO did not identify any specific economic development projects in its 2014-2020 Electric TDSIC Plan, NIPSCO is not proposing a budget for the general category of Economic Development Projects in its 7-Year Electric Plan but that if NIPSCO becomes aware of an economic development project that would be eligible for TDSIC recovery, NIPSCO proposes to add the economic development project during its proposed Plan Update process. He stated that at that time, he was not aware of any proposed Economic Development Projects that would be eligible for TDSIC recovery. He noted that NIPSCO continuously works with community partners to identify potential economic development opportunities. He explained that NIPSCO did understand from its partners in LaPorte County that there may be an opportunity or potential project that could fall under this category. He stated that to the extent NIPSCO receives further information and specific project details from LaPorte County, or any other entity that meets the requirements of the TDSIC Statute, NIPSCO will encourage the requesting entity to work with the Company and its other stakeholders to present any economic development proposal to the Commission and provide sufficient evidence for the stakeholders and the Commission to determine that the estimated costs of the eligible improvements included in the Plan are justified by the incremental benefits attributable to the Plan.

Mr. Caister testified that NIPSCO conducted a meeting with the OUCC and interested stakeholders, including representatives of the NIPSCO Industrial Group, United States Steel Corp., IMUG, LaPorte County and NLMK Indiana on December 3, 2015 and that NIPSCO appreciates the time and attention of the OUCC and the stakeholders during this process. He stated that during the December 3 meeting and based upon the information known at that time, NIPSCO reviewed the lessons learned from previous filings and provided an overview of its 7-Year Electric Plan as well as an overview of the asset health condition methodologies employed in completing its asset registers. NIPSCO also indicated to the stakeholders that while there were no economic development projects for which NIPSCO would be seeking recovery at this time, NIPSCO noted that it continues to review potential economic development projects.

Mr. Caister testified that NIPSCO proposed that in an effort to provide more complete information, NIPSCO proposed to meet with the OUCC and interested stakeholders approximately four weeks prior to making its tracker filings. NIPSCO explained that a four week prefiling meeting would be useful for NIPSCO, the OUCC, and interested stakeholders because at four weeks prior to filing, NIPSCO will have finalized its updated Plan and will have more current actual costs to disclose any cost variances. Subsequent to the stakeholder discussion, NIPSCO received the Remand Order and further considered the discussion at the Commission's TDSIC-related technical conference, which led to some changes to NIPSCO's 7-Year Electric Plan. This was mostly related to the creation of additional asset registers. In order to assist the stakeholders in understanding the alterations made to the plan that was discussed on December 3, 2015, NIPSCO provided additional slides to the stakeholders on December 31, 2015. As of the time of filing, NIPSCO is not aware of any outstanding questions regarding its proposed projects or costs, but recognizes LaPorte County may have concerns regarding the lack of an economic development project to upgrade a specific site in LaPorte County. NIPSCO is committed to continuing to work with LaPorte County, and/or any other interested party, on defined economic development projects that a party or parties wishes to support before the Commission. In addition, NIPSCO recognizes that the OUCC and other stakeholders may continue to ask questions and reserve comment on any further issues that they may identify as a result of the filing.

Mr. Caister testified that NIPSCO intends to comply with Ind. Code § 8-1-39-9(d), states that a public utility that implements a TDSIC under Ind. Code ch. 8-1-39 shall, before the expiration of the utility's approved seven-year plan, petition the Commission for review of the public utility's basic rates and charges with respect to the same type of utility service.

Mr. Caister testified that as required by Ind. Code § 8-1-39-14(a), the annual increase to total retail revenue from the TDSIC is projected to be less than 2% in each year or approximately 0.9% on average over the 7-Year Electric Plan. He illustrated NIPSCO's calculation methodology of the average aggregate increase in its total retail revenue and stated that NIPSCO will include the impact of the 7-Year Electric Plan on individual rates in its tracker filings where the total revenue requirement of the Plan is allocated among NIPSCO's individual customer rates. He stated that in addition to the TDSIC Rate Schedule, NIPSCO estimates that the balance of deferred TDSIC costs will be approximately $80.0 million at the end of 2022, the last year of NIPSCO's 7-Year Electric Plan and that these costs will be a subject of NIPSCO's next general rate proceeding, which must be filed prior to the end of the approved 7-Year Electric Plan. He indicated that at this time, NIPSCO has not determined when it will file that next general rate proceeding. He stated that the timing of the recovery of those deferred costs is not defined in the TDSIC Statute and for these reasons, NIPSCO has not projected the effect on retail rates and charges past the final year of NIPSCO's 7-Year Electric Plan.

Mr. Caister testified that based on today's information, the proposed 7-Year Electric Plan represents the best path forward to, in a cost effective manner, ensure the continued delivery of safe and reliable electric service to NIPSCO's customers. The proposed System Deliverability investments will preserve NIPSCO's ability to serve its peak load through annual system capacity additions where needed. The Aging Infrastructure investments will also maintain system performance through the targeted replacement of assets that are known to be prone to failure and/or obsolete. Because of the sophisticated analyses used to develop the Plan, the reduction in risk associated with the investments provides incremental benefits to NIPSCO's customers and its system as a whole. NIPSCO's proposed 7-Year Electric Plan is a well-developed, flexible and cost effective solution for maintaining safe, reliable service for its customers. Finally, NIPSCO has demonstrated that the Plan includes the best estimate of the costs of the eligible improvements included in the Plan and that the estimated costs of the eligible improvements included in the 7-Year Electric Plan are justified by incremental benefits attributable to the Plan. For these reasons, the Commission should find that the Plan is reasonable and should be approved.

B. Direct Testimony of Russell L. Atkins. Mr. Atkins, Vice President, Electric Engineering for NIPSCO, provided testimony to support the (1) designation of the specific projects contained in NIPSCO's proposed 7-Year Electric Plan as "[e]ligible transmission, distribution and storage system improvements" as that term is defined in Ind. Code § 8-1-39-2, (2) conclusion that NIPSCO has provided the best estimate of the cost of the Plan, and (3) determination that the estimated cost of the Plan is justified by incremental benefits attributable to the Plan. He explained the processes used to identify the specific projects incorporated into the Plan and the cost estimates for those projects, and provided an assessment and prioritization of those projects within the 7-year timeframe of the Plan.

Mr. Atkins sponsored three reports prepared by Black & Veatch (1) Long Term T&D Capital Plan Business Case ("T&D Capital Plan") (Attachment 2-B (Confidential); (2) Review of NIPSCO Asset Registers (Attachment 2-C); and (3) Economic Impacts of Projected NIPSCO Transmission & Distribution Expenditures, 2016-2022 ("Economic Impact Report"), sponsored by NIPSCO witness Timothy R. Caister as Attachment 1-B (Confidential). He explained that the T&D Capital Plan is focused on the objectives of maintaining high reliability performance while proactively replacing aging, high risk equipment across the system. To accomplish this, Black & Veatch outlined the long term plan to address aging assets and documented NIPSCO's risk-based approach to evaluating its transmission and distribution ("T&D") system and how that approach is used to focus long term capital investment (and, by extension, TDSIC funds) towards the highest-risk assets on the system. The T&D Capital Plan includes two appendices: (1) Appendix A, which provides the actual Risk Model results ("TDSIC Risk Model") and (2) Appendix B, which provides the Effective Age Methodology which documents the process used to incorporate conditional data into the TDSIC Risk Model outlines the TDSIC Risk Model asset effective age, the criteria used to assess the condition of the assets and the assumptions used in the modeling. He stated that the Review of NIPSCO Asset Registers is an independent review of NIPSCO's approach used to develop asset registers for projects that were selected based on criteria other than the risk model. He stated that the Economic Impact Report provides the estimated economic impacts of NIPSCO's planned TDSIC expenditures for the State of Indiana, as well as the United States.

Mr. Atkins testified NIPSCO's 7-Year Electric Plan is focused on T&D investments made for safety, reliability, and system modernization. The Plan also makes provision for appropriate economic development projects in the future, although none are proposed at this time. NIPSCO's 7-Year Electric Plan includes necessary investments that enable NIPSCO to continue providing safe, reliable electric service to its customers into the future. The Plan is comprised of two main segments: (1) investments that target replacement of aging assets ("Aging Infrastructure"); and (2) investments intended to maintain the capability of NIPSCO's electric system to deliver power to customers when they need it ("T&D System Deliverability").

He testified the 7-Year Electric Plan also includes investments for a project to replace NIPSCO's current streetlights with light emitting diode ("LED") streetlights. He explained that although the Plan does not include any economic development projects at this time, as appropriate projects are identified and supported, NIPSCO is committed to including eligible economic development investments in its Plan updates. He testified the total estimated capital cost of the 7-Year Electric Plan is $1.33 billion, which includes direct capital, indirect capital and allowance for funds used during construction ("AFUDC").

Mr. Atkins testified the primary goal of the Plan is to deploy a portfolio of reliability investments in electric T&D facilities that preserve NIPSCO's ability to serve peak load, maintain system performance, and ensure the safety of NIPSCO's T&D systems. In doing so, the Plan will reduce the increasing failure risks associated with aging asset populations, ensure the reliable delivery of electric service during periods of peak demand, and target replacement of assets most likely to be prone to failure.

Mr. Atkins testified the Plan is organized as follows:

Plan by Project Category	Provides a high level summary showing the breakout of investment by year for both transmission and distribution.
Plan by FERC Account	Provides a high level summary showing the break down by Federal Energy Regulatory Commission "FERC") Uniform System of Account account number by year for both transmission and distribution.
Project Detail by Year	Provides project detail separately for each year of the Plan (2016-2022). Each line item shows the Project ID, the subcategory, the driver associated with the project, the project title, the anticipated investment for each project (in direct dollars), and the expected number of units or miles of assets included in the project. Detailed scopes and estimate summaries (project estimates) are also included, as appropriate, for Year 1 (2016) and Year 2 (2017) in Appendices 3 and 4, respectively.
Project Detail Summary by Year	Matrix showing all of the projects included in the 7-Year Electric Plan by project category by year showing the total investment of the 7-Year Electric Plan.
Appendix 1	Asset Register for Risk Based Projects
Appendix 2	Asset Register for Deliverability and Condition Based Projects
Appendix 3	2016 Project Estimates
Appendix 4	2017 Project Estimates
Appendix 5	Unit Cost Tables and Methodology, by Project Type
Appendix 6	Register of Streetlights by Municipality

Mr. Atkins testified that over the past two years NIPSCO has been able to make significant improvements in the development of a long term 7-year capital investment plan. Historically NIPSCO did not forecast capital planning at this level of detail for such an extended period of time. Based on feedback received and internal learning through the plan development process NIPSCO has been able to make considerable improvement providing a much greater level of detail utilizing risk modeling, condition based assessment and long range system planning to better define projects that are necessary and included in the plan. Improvements have also occurred in NIPSCO's ability to develop more accurate project estimates including extending Class 3 estimates out to 24 months. Project management and construction has also been able to build on the experience over the past two years becoming more experienced in project planning and execution.

Mr. Atkins testified the Aging Infrastructure investments are projects aimed at reducing reliability risk by replacing or rehabilitating electric T&D assets that are of high consequence and are either approaching, have met, or have surpassed their expected life. Aging Infrastructure investments were identified in two ways. First, NIPSCO worked with the asset management team at Black & Veatch to develop an overall risk model for its power transformers, circuit breakers, and circuits. This was used to develop the proposed 7-Year Electric Plan (the results of the TDSIC Risk Model are included in the T&D Capital Plan attached as Attachment 2-B (Confidential)). The result of this work includes the reports identified above as well as the Asset Register for Risk Based Projects included in the Plan as Appendix 1. An optimized portfolio of electric T&D assets was then selected to be addressed based on the result of this risk analysis. Each of these major electric T&D assets are critical, highly engineered components requiring significant lead time prior to execution. This process included assigning a consequence of failure ("COF") and likelihood of failure ("LOF") to each of the assets.

Mr. Atkins stated that NIPSCO independently evaluated groups of system assets to identify and prioritize the assets within each group with the greatest potential of failure based on their age and condition. Rather than using a complex risk model for these more numerous assets, NIPSCO analyzed its routine testing and maintenance records to identify the individual assets within each group that were most in need of replacement and used the results of that analysis to create asset registers. He stated that Black & Veatch reviewed these asset groups and the methodology to validate the necessity for inclusion in the Plan and sponsored the results of that review in Attachment 2-C. The Asset Register for Deliverability and Condition Based Projects is included in the Plan as Appendix 2. He stated that for those asset classes and programs reviewed, Black & Veatch found that the approach NIPSCO used to select assets for replacement is reasonable. He stated the Review of NIPSCO Asset Registers notes that the vast majority of assets selected take into account NIPSCO's system knowledge through inclusion of asset health/condition data.

Mr. Atkins testified that based on the nature of how specific projects are selected, Circuit Performance Improvement projects are not included in an asset register. He stated that Circuit Performance Improvement investments are determined on an annual basis by analyzing reliability data and determining which circuits are most in need of improvement. For purposes of development of the Plan, expected projects are included in categories such as sectionalization, distribution automation, circuit rebuild, conductor replacement or other identified performance improvement based on root cause. The methodology NIPSCO utilizes to identify these needs and the appropriate solutions are detailed below. NIPSCO performs a structured assessment of its circuits systems on an on-going basis to identify and schedule needed investments well in advance of execution to proactively address circuits with the poorest reliability. The Circuit Performance Improvement investments included in the 7-Year Electric Plan therefore differ from the other projects included in the Plan because the needed investments are identified based on the evaluation of reliability and condition. At the beginning of 2016, NIPSCO will review 2015 performance and determine the 2016 Circuit Performance Improvement projects and develop project scope and cost estimates. These estimates will be provided in NIPSCO's tracker filing. This process will also be used in subsequent years.

Mr. Atkins described the Streetlighting projects, He testified that based on the request for information ("RFI"), a total of 40 communities, out of 111 with NIPSCO-owned streetlights, responded requesting the upgrade of more than 24,000 streetlights. He stated that using a weighted analysis (community investment, projected start date, quantity of lights, etc.), NIPSCO developed a plan to replace the streetlights in all of these communities in addition to the estimated 18,000 streetlights in the balance of NIPSCO's electric service territory during the 7-year timeframe of the Plan. Appendix 6 of the Plan is NIPSCO's Register of Streetlights by Municipality showing the number of streetlights to be replaced by municipality in each year of the Plan. Although engineering may begin earlier, upon receiving a Final Order in this Cause, NIPSCO anticipates a ramp up of installations beginning in mid-2016 (approximately 4,500 streetlights) and an average of approximately 6,250 streetlights per year in subsequent years. NIPSCO will engineer, estimate and execute these projects using the same techniques used for projects of similar size and scope. At this point, NIPSCO has a LED streetlight standard in place and will be issuing a request for proposals to potential lighting vendors as well as determining the most appropriate labor to use for installation.

Mr. Atkins explained that because the TDSIC Statute calls for a 7-year plan, for easiest understanding, NIPSCO has organized its Plan by calendar year. In addition, NIPSCO plans and executes its capital projects and manages its capital budget on a calendar year basis. This does not mean that each project identified in a specific calendar year will be completed within that year. Some projects are multi-year projects and other projects will have items that will need to be completed past the end of a given calendar year.

Mr. Atkins testified that additional costs may be incurred in a subsequent calendar year for a prior year project for a variety of reasons including restoration costs for work completed, vendor invoices, and labor costs incurred but not submitted. NIPSCO accruals are booked in December based on the best information known at that time including both known costs and estimates for work completed but not yet booked. When invoices are received in subsequent months, the actual cost is booked and the prior period accrual is reversed. This process can result in either an additional charge or credit booked to the work order in a subsequent year. There may also be late issued vendor invoices related to work completed that were not known when the accruals were estimated and therefore not incorporated into those accruals. Projects may also be multi-year projects, or may start in one year and end the following year depending on the project start and end dates and project schedule. Mr. Atkins explained that the Project Detail section of the 7-Year Electric Plan will include a column labeled "20xx Actual Costs" in the current year Project Detail sheet (for example, 2016 Project Detail) to allow for the allocation of actual costs incurred in the next calendar year, as well as a row labeled "Prior Year Reconciliation" in the following year Project Detail sheet to show costs incurred in that year relating to a prior year projects. This will allow for the identification of costs associated with a project included in one year that are actually incurred in a subsequent year.

Mr. Atkins testified NIPSCO recognizes the fact that the dangers caused by electromagnetic pulse ("EMP") and geomagnetic disturbance ("GMD"), although remote, pose a serious and, in some scenarios, catastrophic threat to the electric system. These magnetic disturbances can be intentional, manmade in the case of EMPs, such as those from directed energy weapons or nuclear blasts, or naturally occurring GMDs, such as solar flares. The two ways to prepare for such an event are system hardening (designing systems to withstand such an event) and system resiliency (the ability to restore power quickly after an event). TDSIC projects such as relay upgrades utilizing fiber optic communication links hardens the system thereby decreasing the risk from such an event. TDSIC deliverability projects such as those that replace aging transformers with newer and in some cases redundant units both harden the system and provide operational flexibility. Many technologies such as enhanced control house shielding are in their infancy and not implemented as a regular utility practice. NIPSCO will continue to monitor the trends in this area and adopt new technology as it is proven and acceptable as a best utility practice. Microprocessor technology is also developing testing standards designed to reduce the impact of a magnetic disturbance. System hardening and resiliency is also impacted through the replacement of many different types of aging assets due to improved design standards that have evolved over time. For example, the class of pole used today is greater than that used 30 or 40 years ago. Steel towers are also addressed in the Plan by identifying areas of deterioration or strength reduction bringing those structures up to current requirements.

Mr. Atkins testified that in developing the 7-Year Electric Plan, NIPSCO reviewed all of its electric T&D assets. The NIPSCO electric transmission system consists of 353 circuit miles of 345 kV, 757 circuit miles of 138 kV and 1,693 circuit miles of 69 kV transmission lines. In addition, NIPSCO has 61 transmission substations. NIPSCO serves more than 461,000 customers in Northern Indiana, primarily through more than 900 distribution circuits. These circuits operate at a nominal voltage of 34.5 kV, 12.5 kV, and 4 kV, and radiate from 244 distribution substations. There are more than 7,800 miles of distribution overhead line and 2,380 miles of underground cable. NIPSCO's review included all transformers, circuit breakers, system protection devices, and other ancillary substation equipment in its transmission, sub-transmission, and distribution substations. Also included are the structures and the corresponding overhead and underground conductors associated with the transmission, sub-transmission, and distribution circuits. In this review, NIPSCO confirmed the following key facts about its electric T&D infrastructure:

- NIPSCO owns, operates, manages and controls T&D plant and equipment within the State of Indiana that is in service and used and useful in the furnishing of electric service to the public. NIPSCO has maintained and continues to maintain its properties in a reliable state of operating conditions.

- The NIPSCO electric system grew significantly during the 1960s and 1970s. Many assets installed during this era and before are reaching the end of their useful lives and in many cases are based on technology developed in the 1950s. These assets have increasing failure probabilities that will cause reliability degradation. This statistical LOF is increasing every day.

- There are certain asset segments that are demonstrating specific failure trends or unique reliability concerns. Included in this segment is a population of unjacketed underground cable that is approximately 40 years old. Also included in this segment are the remaining 4kV distribution circuits which are at least 50 years old. These circuits are geographically isolated with limited contingency in the event of failure.

- Some of NIPSCO's system protection devices are obsolete and cannot protect the electric system and key assets in the manner consistent with modern standards.

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

Mr. Atkins described how NIPSCO identified the T&D System Deliverability investments to include in the 7-Year Electric Plan. He stated that NIPSCO has reliability planning criteria and assessment practices that are used to plan for adequate system deliverability under expected peak load conditions when the T&D systems are stressed. Through these criteria and practices, various T&D projects are identified and evaluated to accommodate customer demands. For the transmission system, NIPSCO's planning criteria is aligned with the North American Electric Reliability Corporation ("NERC") Reliability Standards, which includes peak load analyses along with other study scenarios targeted at testing the system under stressful situations (e.g., multiple contingencies at the same time). For reference, NIPSCO's Transmission Planning System Assessment Methodology and Planning Criteria dated March 10, 2014, which is also posted on the Midcontinent Independent System Operator, Inc.'s ("MISO") website, is attached hereto as Attachment 2-D. These criteria help ensure a transmission system that will operate reliably and remain resilient through multiple outages without causing cascading outages or widespread load loss and can accommodate near- and long-term customer load growth. These outcomes support not only NIPSCO's customers, but also the overall reliability of the NERC Bulk Electric System. For the distribution system, changes in electric demand associated with current and future customer growth often times require investment in the form of expanded, upgraded or additional facilities. These investments are made to ensure sufficient system capacity is available for NIPSCO's customers under peak load conditions when the system is stressed. The Company follows planning criteria used to identify areas of needed improvements under these peak conditions. These criteria call for mitigation plans to be developed when equipment limits are exceeded for normal system operations as well as under the single worst contingency. Distribution operating and design criteria rely on NIPSCO electric line and substation capacity capabilities are based on NIPSCO's line and substation design standards, along with specific equipment manufacturer ratings. Voltage operating criteria are based on the American National Standards Institute ("ANSI") Standard C84.1 ("Electric Power Systems and Equipment - Voltage Ratings (60 Hertz)") and Indiana Administrative Code 170 IAC 4-1-20.

Mr. Atkins testified the T&D planning processes both utilize power system modeling and analysis software to perform their annual system assessments based on data collected by NIPSCO on a routine cycle. The Transmission Planning group utilizes models developed through NERC and ReliabilityFirst. These organizations work together to develop joint models that the utilities use in local transmission planning analyses. NIPSCO's Distribution Planning group utilizes models built locally utilizing NIPSCO's Geographic Information System data. Both the Transmission and Distribution Planning groups use their respective models to run scenarios that look at current and future projected conditions including load growth assumptions. These analyses consider both normal and emergency operating conditions where contingencies are introduced to stress the system to find vulnerabilities that could impact the reliability of customers' electric service. Mitigation plans are developed based on these analyses. He stated that in addition to these simulated tests utilizing power system models, NIPSCO's electric system planners gather input from many teams within NIPSCO to validate modeled results and to capture issues that may not be identified in the simulation tests. This input includes operating data such as bus voltage or current values, service requests or operating mitigation steps taken in the past (e.g. system reconfiguration to redirect flows).

Mr. Atkins testified the 2016 and 2017 Transmission System Deliverability projects include the replacement of one 138/69kV transformer, the replacement of substation capacitor switches, and the reconfiguration and extension of 69kV lines. The 2016 and 2017 Distribution System Deliverability projects include five 12kV power transformer replacements, two switchgear replacements, ten 12kV line re-conductors, and one new distribution substation in Goshen, Indiana. These projects address system capacity issues experienced during peak load. He stated that NIPSCO has identified and included in the Plan the T&D System Deliverability investments that are needed in future years based on the current planning models. These projects are the product of on-going planning cycle iterations. The project detail will be provided in a future plan update. It is important to note that these improvements might change in subsequent planning cycles as NIPSCO's T&D system changes and as new customers are added. In the subsequent years, NIPSCO anticipates replacing or upgrading existing substation equipment including transformers, breakers, relays, disconnect switches and other associated equipment and adding new substations as demonstrated by the planning process. NIPSCO also anticipates re-conductoring existing circuits, replacing existing switches with increased capacity units as well as adding new circuits. In addition to the specific projects included in the Plan for 2016 and 2017, NIPSCO anticipates the construction of a total of three new distribution substations -- one each in 2018, 2020 and 2022. Through its analysis of trends in load growth and expectations about future demand, NIPSCO's Distribution Planning group has targeted three areas in NIPSCO's system (southern Hobart area, southern Portage-Chesterton area, and the east central Valparaiso area) that are likely to require new distribution substations to meet customer demand. The cost estimates for the three new substations in 2018, 2020 and 2022 are Parametric Class 4 estimates 4) based on the most recently completed similar substation project (Buchanan Distribution Substation) and escalated using the Gross Domestic Product deflator.[3] In the subsequent years, NIPSCO anticipates line construction work associated with substation source and feeder line extensions and upgrades necessary to integrate the new substations in the targeted growth areas.

Mr. Atkins described the significance of replacing aging infrastructure. He testified that aging infrastructure is a common issue faced by utilities. The electric system is characterized by technology developed in the 1950s or earlier. Much of the infrastructure was constructed in the 1960s and 1970s during a rapid buildout of the electric grid using the best technology available

[3] See Appendix 5 at p. 41.

at the time. These assets have now exceeded the projected life expectance by many years and have a failure rate that continues to increase. As this large asset base continues to age it produces a higher concentration of projects similar to the original buildout that must be replaced to maintain the increasing level of system reliability expected by today's customers. As these assets are replaced, new technology is introduced improving system performance by replacing the obsolete technologies currently in service. The additional benefits achieved include improved system performance impacting safety, reliability, and operational performance including system hardening and resiliency.

Mr. Atkins testified that aging infrastructure is a significant portion of the Plan and the projects have been separated into three categories: (1) risk-ranked projects, (2) projects ranked using other data sources, and (3) assets included in the TDSIC Risk Model, but selected and prioritized based on independent assessments.

- Risk Ranked Projects. Overhead and underground circuit rebuild projects, transformers, and circuit breaker assets are identified and prioritized on the Asset Register for Risk Based Projects (Appendix 1 of the Plan). These are major T&D projects requiring significant lead time and planning to execute.

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

- Projects Ranked Using Independent Assessments. Projects in this category include oil circuit breakers, wood poles, steel tower rehabilitation, underground cable, circuit performance and system deliverability and are included Asset Register for Deliverability and Condition Based Projects (Appendix 2 of the Plan). Oil circuit breakers/reclosers is an obsolete technology targeted for retirement in the Plan due to operational and safety concerns. They will be replaced with vacuum or gas breakers improving operability, reliability and safety.

  NIPSCO currently has a wood pole inventory of 302,000 poles with an average age of approximately 40 years. The Plan is based on a 10-year inspection cycle, with approximately 5-6% of inspected poles being replaced each year, to ensure the integrity of the transmission and distribution system and to improve system reliability and safety. The Wood Pole Inspection project is defined by specific geographic grid and individual assets to perform an inspection of approximately 207,000 poles over the 7-years of the Plan to determine the current condition. Once inspected, the pole will be identified for life extending treatment or replacement based on this assessment. Replacement poles meet current day standards represented in the National Electric Safety Code ("NESC"). Frequently this results in larger class poles than were previously installed, which in turn improves system hardening or performance during major event days.

The Steel Structure Life Extension project is similar in nature to the wood pole inspection project. Steel towers have a greatest point of risk at the ground line due to environmental conditions. The Plan includes a detailed structure list by circuit identifying each tower to be inspected for each year of the Plan. NIPSCO anticipates inspecting approximately 3,000 structures over the life of the Plan, with approximately 20% requiring rehabilitation. This will put the steel towers on a 10-year inspection cycle as well. As the steel tower is inspected, any identified defects are addressed to return the structure to original condition or better, which results in improved system hardening and reliability.

The Underground Cable Replacement project is the replacement of non-jacketed underground cable. Underground cable became more mainstream as technology developed during the 1970s and into the 1980s. This early design was a non-jacketed cable with early generation dielectric composition. NIPSCO is currently experiencing an increasing rate of failure of this early generation cable, which results in increased outages, which can be of a long duration due the repair process. Much of the cable requires direct replacement due to the non-jacketed design, while some of the 1980s cable that does have a jacket can be treated for life extension based on a condition assessment. The Underground Cable Replacement project includes a detail list of all cable planned for replacement or rehabilitation during the life of the Plan. Replacement of this vintage of cable will improve system reliability by replacing obsolete technology with new cable designs expected to last more than 40 years.

The Circuit Performance Improvement projects are directly targeted at distribution lines indicating below average performance based or reliability indices that are tracked through the NIPSCO outage management system. Based on outage data, each distribution circuit is ranked and evaluated each year based actual performance. This data is used to create a circuit list resulting in approximately 5 projects each year to improve the performance of those identified circuits. To provide the best possible outcome for reliability improvement and customer impact, this list is refreshed using the most current information throughout the life of the Plan. Several projects for 2016 have been identified, with the remainder being determined as the assessment of 2015 performance is completed in early 2016.

Mr. Atkins stated that NIPSCO's Aging Infrastructure investments include replacements from all categories within the TDSIC Risk Model including: transformers, breakers, and overhead and underground circuit rebuilds. Another category included in the Plan is system protection modernization efforts such as breaker relay upgrades and fiber optic lines. The Plan includes not only replacing aged assets, but the extension of the useful life of assets. The Plan also addresses assets such as arresters, batteries, switches, annunciators, and potential transformers.

Mr. Atkins testified when considering the proactive replacement of some of the aging infrastructure assets, NIPSCO used a systematic risk model to quantify the criticality of three types of major T&D assets to the overall electric system: (1) overhead and underground circuits, (2) transformers, and (3) circuit breakers. The results of that risk analysis is the Asset Register for Risk Based Projects (Appendix 1 of the Plan). The model uses this standard definition of risk: Risk = COF x LOF. Through a quantified risk-scoring model, each major asset that is part of the NIPSCO T&D system is scored based on the different COF and the asset's LOF with 1 being lowest and 5 highest. Additional detail on the risk scoring approach and analysis results is detailed in the T&D Capital Plan (Attachment 2-B (Confidential)). This document was one of the building blocks of NIPSCO's proposed 7-Year Electric Plan. Applications of that risk-based scoring and how the results are used to inform the capital expenditure forecast for the system are also included in the T&D Capital Plan (Attachment 2-B (Confidential)). In short, the approach is used to allocate capital spending towards the assets with the highest risk scores. While the COF for an asset does not necessarily change a great deal with the passage of time (unless redundancy is added to the asset base or system configurations alter the impact of the asset), the effect of infrastructure aging is that the likelihood of failure increases with each year, which results in an unacceptable level of risk for the utility. NIPSCO's 7-Year Electric Plan will reduce that risk in an efficient manner. It is important to note that the Plan has model constraints that consider NIPSCO's operational limits.

Mr. Atkins testified that in determining the LOF, NIPSCO utilized the associated survivor curve for each category of equipment. Survivor curves are widely used by utilities as part of depreciation studies to estimate the probable average service life of different assets and to set depreciation rates in line with those lives. Service life is defined as the period in years from the initial installation to the retirement date from service as recorded in the continuing property records ("CPR") of the utility. A plot of the retirement dispersions calculated from the CPR data for each FERC account is used to determine "best fit" Iowa survivor (mortality) curves and probable life. Likelihoods of failure over the next seven years were then derived from the survivor curves by taking a "seven year forward look" on each asset's survivor curve. This approach is detailed in the T&D Capital Plan (Attachment 2-B (Confidential)). In addition, NIPSCO incorporated condition data obtained from field observations. In order to target the poorest-condition assets on its system, the TDSIC Risk Model explicitly estimates and incorporates asset condition information into the scoring of T&D system risk. This has been accomplished through development of asset health indices ("AHI") for different T&D asset types, including substation transformers and breakers. The AHI is a condition scoring algorithm used to calculate an effective age for each asset. Effective age is then used in the TDSIC Risk Model to develop an enhanced measure of T&D system risk. The benefits of incorporating asset condition information into the TDSIC Risk Model is that NIPSCO is able to target its poorest-condition assets, in addition to the most critical assets, within its 7-Year Electric Plan. This will help NIPSCO to reduce the likelihood of asset failures and to decrease the impact of aging infrastructure on its customers. Finally, using the condition data, NIPSCO determined the "effective age" of each of these assets. The effective age of an asset is the result of adjusting an asset's chronological age due to relative differences in the asset's current condition as compared to an expected condition. The condition of an asset can be influenced by many factors such as operating conditions, service history, number of operations, loadings, and demand cycles. This information is gathered from NIPSCO's maintenance and testing programs and includes information and data from analytical testing as well as visual inspections.

Mr. Atkins testified the COF was estimated through a qualitative scoring analysis involving inputs from subject matter experts, including staff involved in the design, operation, and maintenance of the asset. Multiple electric T&D planning, engineering, and operations professionals responsible for each part of the system--transmission, sub-transmission, and distribution--were engaged in this scoring process. The process consisted of a series of criticality workshops including brainstorming sessions and several follow-up meetings and discussions to finalize the consequence criteria for each part of the system. The consequence criteria were determined for each asset within each system. The criteria considers a number of factors related to an asset failure on the system and are categorized into (1) Customers Served/Lost, (2) Loss of Generation, (3) Reliability, (4) Safety and Environmental, and (5) Customer Type. Each of these criteria were rated by NIPSCO staff on a scale of 1 to 5 (low to high) based on expert experience, system knowledge and quantifiable data that was applicable. Once tabulated, the ratings were used to calculate a consequence score on a weighted average of the criteria that varies based on the system voltage, that is, transmission, sub-transmission and distribution. The detailed definitions for each system and asset are included in the T&D Capital Plan (Attachment 2-B (Confidential)). As with LOF, the methodology utilized to assess consequence of failure is detailed in Appendix A of the T&D Capital Plan (Attachment 2-B (Confidential)). NIPSCO reviewed and considered two alternative LOF scenarios in the development of its proposed 7-Year Electric Plan (LOF >= 4 case and LOG 5 case).

Mr. Atkins testified NIPSCO's approach in the development of the Plan was to reduce reliability risk in the most efficient manner possible. In pursuit of this goal, the Company used the LOF 4 / LOF 5 investment scenarios described above as the bounds of reasonable investment levels. These bounds provide the opportunity to replace assets near the end of their useful lives while not replacing assets prematurely. He explained Appendix A of the T&D Capital Plan (Attachment 2-B (Confidential)) provides the raw output of the risk rankings. NIPSCO then used the TDSIC Risk Model results as well as system constraints to develop an optimized aging asset replacement plan, which is provided in the Asset Register for Risk Based Projects (Appendix 1 of the Plan). The optimization methodology used in the development of the Plan sought to achieve the greatest risk reduction possible for the dollars invested. This included moving projects earlier or later in the planning schedule to create operational and construction efficiencies.

Mr. Atkins testified that each year, NIPSCO will review the risk ranked assets and update the COF, LOF and condition assessment. The results of that review will be used to update the risk reduction optimization, and, therefore the Asset Register for Risk Based Projects (Appendix 1 of the Plan), which could mean projects are moved up or back in the 7-Year Electric Plan to best utilize TDSIC funding to reduce risk.

Mr. Atkins testified that some assets contained in the TDSIC Risk Model have been identified through independent criteria such as safety, documented performance issues, or the availability of spare parts. Their replacement is also considered due to constructability efficiencies gained when performing other system modernizations. These projects include the 4kV Upgrades, Breakers associated with Relay and Control Modernization, Recloser Replacements, Power Transformers, Circuit Performance Improvements, and Underground Cable Replacements.

Mr. Atkins explained that each of these assets has a specific reason why a risk-based assessment is not the best way to design the projects as follows:

- 4kV Upgrades. NIPSCO's 4kV system is approaching 65 years of age. While this would produce a high ranking LOF score, most 4kV assets are very lightly loaded creating a low COF. Currently the 4kV system is isolated and unable to be tied to NIPSCO's current standard 12.5kV distribution operating voltage.

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

- Recloser Replacements. NIPSCO has chosen to target its substation oil reclosers due to a safety concern. This type of equipment has demonstrated a potential to fail violently and the reclosers are filled with oil that can have a negative environmental impact in the event of a leak or other failure. Therefore, a project to replace these reclosers despite what the risk model may show is appropriate.

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

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

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

Mr. Atkins explained the Underground Cable Replacement project. He testified the Plan includes approximately 435 miles of unjacketed underground primary cable. The Project Detail section of the Plan shows the number of miles expected to be replaced each year. This represents most of the unjacketed underground primary cable in NIPSCO's system, which is approximately 18% of NIPSCO's total underground primary cable population. The 1970s vintage underground cable has demonstrated a high rate of failure at NIPSCO. Prior cable testing indicates that cable failures in this population segment are 13% above the national average. Due to the complexity of repairs, underground cable outages are among the longest duration outages. Replacement of these segments of un-jacketed cable will reduce this known risk in the most suspect vintage cable. In addition, this replacement process will create circuit loops where radials previously existed, reducing outage duration risk. He testified NIPSCO's asset management team uses a progressive elaboration process in evaluating its entire underground system performance utilizing outage information and additional input provided by its local operations supervisors. This analysis provides historical data on the poorest performing sections and circuits and is used to prioritize the order of replacement of the unjacketed underground cable. Sections may also be selected and placed on an accelerated schedule if they are failing at a higher than expected rate. All sections of cable planned for replacement in the Plan is included in Appendix 2 of the Plan.

Mr. Atkins explained the Fiber Optic Cable Installation projects. He testified the Fiber Optic Cable Installation projects are aging infrastructure investments that improve communication between protective devices, which in turn improves security and reliability of NIPSCO electric grid, the project is not evaluated as part of the TDSIC Risk Model. Selective high-speed clearance of faults on high voltage transmission lines is critical to the security of the power system. Modern system protection equipment provides more data and typically includes two-way communication across a large and well-coordinated network of devices. With older equipment, the lack of sufficient data from the device as well as the inability to communicate with many devices at the same time increases fault response times. Fiber optic cable provides the communication medium for these modern protective relay schemes. He testified fiber optic cable installations are performed in conjunction with relay upgrades. Relay upgrades are selected and prioritized by system needs in order to protect equipment and circuits from the consequences of overvoltage, overload, and short circuit conditions. A Fiber Optic Cable Installation project will take place where existing communication paths will not support modern protective relay installations. Fiber optic cable installations will improve relay system protection of the transmission system while optically isolating the communication system from outside influences such as magnetic disturbances, lightning strikes or other communication interruptions. These are Aging Infrastructure investments that are included in the Deliverability and Condition Based Asset Register (Appendix 2 of the Plan).

Mr. Atkins explained the projects included in the Asset Register for Deliverability and Condition Based Projects as follows:

- The **Arrester Replacements** project [Transmission Project ID TSA1 and Distribution Project ID DSA1] is designed to replace 5-10 transmission arresters and 10-11 distribution arresters per year. The number of arresters replaced in a given year varies according to the voltage levels of the units being replaced. These projects are listed in Appendix 2 of the Plan. Arresters protect equipment from lightning and switching surges. The number of assets to be replaced each year was determined by reviewing historical trends and considering arrester replacements that would be included with other projects such as breaker and transformer replacements. NIPSCO will replace the assets on a proactive basis and update the replacement list as new asset health data becomes available. NIPSCO selected the particular units to be replaced in a particular year by considering age and condition data, historical model performance data, linkages to other projects, and infrared scans performed by engineers. Arresters are selected for replacement based on vintage, historical performance, condition and criticality of protection. The arresters included in the Plan are porcelain design from the 1950s with lower protection capability and higher failure mode resulting in high velocity fragmentation when they fail. Each of these arresters will be replaced with current design polymer units offering improved overvoltage protection and a non-fragmentation outer insulation. Greater transformer and breaker protection will result, as well as improving safety by eliminating the porcelain failure point.

- The **Battery and Charger Equipment Replacements** project [Transmission Project ID TSB1 and Distribution Project ID DSB1] is designed to replace 10 transmission batteries and chargers and 13 distribution batteries and chargers each year. These projects are listed in Appendix 2 of the Plan. Batteries provide the source of control power for substation equipment including relays, breakers, transformers, and communications equipment. Station batteries are critical during emergency events allowing protective devices to operate properly during abnormal operating conditions. This includes events such as transmission or distribution outages or loss of station service. Replacement batteries are determined by a combination of age and condition. Maintenance crews perform regular tests on batteries, including inter-cell and intra-cell resistance checks, specific gravity readings, and voltage tests to evaluate battery condition. The number of assets to be replaced per year was determined by reviewing historical replacement rates and the adequacy of these historical replacement rates to stay ahead of unplanned failures. NIPSCO will replace the assets on a proactive basis and update the replacement list as updated asset health data becomes available.

- The **Potential Transformer ("PT") Replacements** project [Transmission Project ID TSPT1 and Distribution Project ID DSPT1] is designed to replace 6-8 transmission potential transformers and 3-4 distribution potential transformers per year. The number of Potential Transformers replaced in a given year varies according to the voltage levels of the units being replaced. Potential transformers step down the high voltage to a level that can be utilized by relay and control equipment. The number of Potential Transformers replaced in a given year varies according to the voltage levels of the units being replaced. The number of assets to be replaced each year was determined by reviewing historical trends and considering potential transformer replacements that would be included with other projects such as breaker and transformer replacements and are included in Appendix 2 of the Plan. NIPSCO will replace the assets on a proactive basis and update the replacement list as updated asset health data becomes available. Potential transformers have been identified for replacement based upon age and condition.

- The **Substation Switch Replacements** project [Transmission Project ID TSSW1 and Distribution Project ID DSSW1] is designed to update 4 existing transmission and 4 existing distribution ground switch protection schemes to circuit-switcher based protection schemes per year. Ground switch protection schemes were commonly utilized when the system was originally constructed. Replacing these schemes with modern circuit switcher protection will improve system protection by greatly reducing overall fault clear times, reducing fault stress on power transformers and minimizing the impacted area during a fault condition. This project involves replacing the ground switch with a circuit-switcher and upgrading and wiring the relays accordingly. The number of assets to be replaced each year was determined by subject matter experts considering factors such as which units would have the greatest impact and reliability improvement and how many could be completed considering constraints caused by other projects. NIPSCO selects the particular units to be replaced in a particular year by reviewing field data for problematic and very old model switches. After age, condition, and model problems are addressed, the level of substation source circuit fault current will drive the relative order of subsequent transformer ground switches to be replaced. Each project is listed by year in Appendix 2 of the Plan.

- The **LTC Control Upgrades** project [Transmission Project ID TSRU1 and Distribution Project ID DSRU1] is designed to upgrade 20 transmission load tap changers ("LTCs") in years 2016 and 2017 and 28 and 62 distribution LTCs in years 2018 and 2019, respectively. LTC controls regulate the voltage on a transformer. Older models are an analog design and used discrete components that fail due to age and condition. The number of assets to be replaced each year was determined by anticipated failure rates submitted by subject matter experts determining the optimum number of units that increased system reliability while also considering constraints caused by other projects. NIPSCO will replace the assets on a proactive basis. NIPSCO selects the particular units to be replaced in a particular year by reviewing age, condition, and operating history. Each LTC control upgrade is listed by year in Appendix 2 of the Plan.

- The **Annunciator Replacements** project [Project ID TSRU2] is designed to replace 5 transmission annunciators each year. Annunciators provide local and remote indication of equipment problems. The number of assets to be replaced each year was determined by subject matter experts determining the optimum replacement rate based on existing annunciator reliability and expected life, spare parts availability, linkages to other projects, and constraints caused by other projects. NIPSCO selects the particular units to be replaced in a particular year by reviewing age, condition, and operating history and will replace the assets on a proactive basis. Each annunciator replacement is listed by year in Appendix 2 of the Plan.

- The **Line Switch Replacements** project [Transmission Project ID TLSW1 and Distribution Project ID DLSW2] is designed to replace 10 transmission switches and 17-32 distribution switches each year. Switches provide positive indication that equipment is disconnected for safety and operational purposes. The number of assets to be replaced each year was determined by subject matter experts after reviewing logs of equipment operating history, equipment, age and type of switch. Each line switch replacement is listed by year in Appendix 2 of the Plan.

- The **Steel Structure Life Extension** project [Project ID TLST1] is designed to extend the life of NIPSCO's steel structures or rehabilitate those that do not meet the accepted strength requirements. This project is necessary to address NIPSCO's aging steel structure population that is continuing to deteriorate. As I discussed above, over the 7-years of the Plan NIPSCO will inspect approximately 3,000 structures with approximately 20% of those assets inspected requiring some type of rehabilitation. The number of assets to be addressed each year was determined by a 10-year inspection cycle and anticipated rehabilitation rates. NIPSCO has identified each structure to be inspected for each year of the Plan. Based on inspection, each structure will have the appropriate life-extending improvements made. This project will increase transmission system reliability through system hardening and resiliency.–Each structure to be inspected is listed by year in Appendix 2 of the Plan.

- The **Wood Pole Life Extension** project [Project ID DLWP1] is designed to inspect, treat, and replace NIPSCO's wood pole population. Wood poles are the largest asset classification on the T&D system. With the average age wood poles being greater than 40 years it is necessary to actively assess the condition and make any necessary replacements to ensure integrity of the system. This is accomplished by development of a 10-year rolling inspection of each pole to determine condition and to replace or treat the pole for life extension if necessary. NIPSCO has provided a list of each grid to be inspected over the next 7 years and each pole within the grid and when it will be inspected. The inspection is based on industry standard methodology to determine remaining life. With each inspection, the pole will either be treated to reduce future decay, or, if it does not pass the test, the pole will be replaced. The pole inspection, treatment and replacement project improves system reliability, safety and system hardening during major event days by ensuring all poles meet the strength requirements set forth in the NESC. This project is necessary to support and replace NIPSCO's aging wood pole population. NIPSCO plans to inspect approximately 207,000 poles over the life of the Plan. It is anticipated that approximately 5-6% of the inspected poles will be replaced. The number of assets to be addressed each year was determined by annual inspection cycle and anticipated rejection rates. Each pole to be inspected by year is included in Appendix 2 of the Plan.

- The **Distribution Power Transformers** project [Project ID DSTU1] is designed to replace one or two distribution transformers per year, with the exact number per year determined by the voltage and size of the transformer chosen by the risk model. Power transformers represent an asset class with the greatest lead time from manufacturers. This extended lead time increases the associated risk due to the amount of time required to replace the unit when a failure occurs. Although NIPSCO has taken steps to provide spare units through inventory or other system spare programs in the industry, the preferred method is to replace a high risk unit prior to failure. The Distribution Power Transformer project is intended to replace transformers that have been determined by the TDSIC Risk Model to have the highest probability of failure, regardless of the consequence of failure. NIPSCO is proactively replacing transformers that rank the highest and are at greatest risk of failing. NIPSCO determined the number of transformers that are expected to actually fail each year based on subject matter experts, test data and anticipated failure rates. This project will improve system performance by removing high risk units from service through a planned event that will reduces or eliminate the need for a customer outage. Each transformer to be replaced is included in Appendix 2 of the Plan.

- The **Recloser Replacement** project [Project ID DSBRU1] is designed to replace 101 distribution-class reclosers over the course of 2016-2018. Reclosers are an automatically operated switch designed to operate and protect an electrical circuit from overload or short circuit. The current reclosers are oil-filled equipment based on 1950 design standards, which will be replaced with current technology vacuum breakers with magnetic actuators and microprocessor relays. The number of assets to be replaced per year was determined by maximizing the number of replacements per year while maintaining system reliability. NIPSCO will replace the assets on a proactive basis from a list of predetermined units. NIPSCO selects the particular units to be replaced in a particular year by considering system constraints and construction efficiencies. Benefits associated with these projects include improved system protection, data acquisition, equipment safety, and customer experience due to reduced outage events associated with the oil reclosers. Each recloser projects is listed by year in Appendix 2 of the Plan.

- The **Switches to Clear Incoming Lines** project [Project ID DLSW1] is designed to replace 18-42 incoming line switches per year. Incoming line switches provide a visible means to verify the incoming line to a switchgear or recloser from an incoming circuit has been disconnected from the distribution circuit. The number of assets to be replaced per year was determined by maximizing the number of replacements per year while maintaining system reliability. NIPSCO will replace the assets on a proactive basis from a list of predetermined units. NIPSCO selects the particular units to be replaced in a particular year by considering system constraints, construction efficiencies, and linkages to other projects. Each of the projects is listed by year in Appendix 2 of the Plan.

Mr. Atkins testified capital dollars at NIPSCO are separated into two segments: (1) direct capital and (2) indirect capital. Direct capital represents costs such as the materials and equipment installed and the labor costs of the workers performing the construction. Typically, these are costs that are incurred at the job site. Vendor related direct costs are procured through the use of a Material Requisition ("MR"). A purchase order ("PO") is required to order goods or services. To initiate a PO with a vendor, an MR is initiated and routed for approval. The MRs related to TDSIC projects are labeled with a specific route code to ensure they are first routed to the TDSIC Project Controls Team, who then routes the request for required approvals. The MRs are approved by the Project Execution Leaders depending upon the dollar amount of the request. The Procurement group then generates a PO, which is identified as a TDSIC PO. This TDSIC route code on the PO ensures that TDSIC invoices are routed to the TDSIC Project Controls Team for validation. The TDSIC Project Controls Team routes TDSIC invoices to the TDSIC Project Execution group for two levels of approval.

There are additional overheads that are also associated with capital projects and must be capitalized in order to comply with Generally Accepted Accounting Principles ("GAAP") but that often cannot be charged directly to a specific capital project work order. These capital costs tend to be incurred away from the job site. NIPSCO groups these indirect capital costs into three categories: (1) overheads, (2) stores, freight and handling, and (3) AFUDC. He explained the overheads, stores, freight and handling are indirect costs that must be capitalized for GAAP purposes. This component of indirect capital represents costs that NIPSCO incurs to procure materials and equipment. Generally, this represents the payroll for NIPSCO's supply chain and procurement functions. It also includes labor costs and other warehousing expenses associated with NIPSCO's warehousing function for inventoried materials and supplies. The last component of NIPSCO's indirect capital is AFUDC for which NIPSCO has presented its methodology numerous times before the Commission. In NIPSCO's 7-Year Electric Plan, the schedules separate indirect capital into only two components: AFUDC and non-AFUDC (indirect capital). He testified all three of the indirect capital components must be capitalized in order to conform with GAAP for public utilities. NIPSCO has consistently applied these accounting principles for both direct and indirect capital costs for years including during the test year in its last general rate proceeding in Cause No. 43969. He testified that amounts presented in the 7-Year Electric Plan for indirect capital and AFUDC have been forecasted based on the historical levels and relationships of these costs and also the expected level and timing of direct capital spend included in the Plan.

Mr. Atkins testified the **Circuit Performance Improvement** project [Project ID DLCP1] is designed to improve reliability on NIPSCO's worst performing distribution circuits and circuit taps as determined by annual evaluation of performance. This program benefits customers with the poorest electric reliability based on operational metrics. The number of assets to be replaced per year was determined by the extent of improvements needed on the highest priority circuits and taps. NIPSCO selects the circuits or taps to be included in the program based on operational data that is gathered on a daily basis in the outage management system. This outage data is used to summarize performance on an annual bases to prioritize circuits or taps in the greatest need of improvement. Circuits that rise to the top are placed on the list each year as the most recent data is available. Each circuit is then reviewed in detail to determine the cause of the performance and to implement identified remediation that will improve performance. This project has a direct impact of customer experience by actively pursuing circuits and taps that have a track record of higher than average outages. Projects for 2016 and future year projects will be identified based on the previous year's data as it becomes available and will be included in the plan as it is updated on an annual basis. NIPSCO will begin evaluating 2015 data in early 2016 and will have the balance of the 2016 projects determined by the time it files its TDSIC tracker.

Mr. Atkins testified the total estimated capital costs associated with NIPSCO's 7-Year Electric Plan is $1.33 billion. This represents $1.18 billion of direct cost, $145 million of indirect capital and $11 million of AFUDC. Indirect capital includes costs which are incurred in performing capital projects but are not charged directly to a specific work order. These costs include general administration related to construction activities (e.g. accounting/clerical processes), insurance premiums, and employee benefits such as pension and medical costs. The estimate for AFUDC is based on, among other things, the estimated direct and indirect project costs, estimated timing of the expenditures and current financing costs (which change over time). As discussed above, the capitalization of these costs align with GAAP for public utilities and is also consistent with NIPSCO's internal accounting processes which have been in place for years including during the test year used in NIPSCO's last general rate case.

The annual amounts for direct capital costs, indirect capital costs and AFUDC included in NIPSCO's 7-Year Electric Plan is as follows:

	Year 1 2016	Year 2 2017	Year 3 2018	Year 4 2019	Year 5 2020	Year 6 2021	Year 7 2022	Total
Direct	$122,929,842	$102,196,517	$150,450,000	$199,550,000	$199,250,000	$202,500,000	$199,300,000	$1,176,176,359
Indirect	$15,472,886	$13,658,295	$18,426,332	$22,857,004	$23,790,155	$24,829,837	$25,494,325	$144,528,834
AFUDC	$2,364,874	$1,304,435	$1,383,314	$1,706,819	$1,520,017	$1,502,070	$1,467,313	$11,248,842
Total	**$140,767,602**	**$117,159,247**	**$170,259,646**	**$224,113,823**	**$224,560,172**	**$228,831,907**	**$226,261,638**	**$1,331,954,035**

Mr. Atkins explained that a cost estimate is developed at a point in time, and it is based on the information known when the estimate is developed. As the project progresses, the information used as inputs into the cost estimation process becomes more accurate. There are different techniques used by project managers to develop a cost estimate for a project.

- Analogous Class 5 (the estimate is based on expert judgment and overall system factors) – these estimates have very little of the total project defined (0 – 2%) and require very little engineering in order to estimate.

- Parametric Class 4 (the estimate is developed using application of similar type estimates and specific equipment factors) – these estimates are done at about 1 – 15% of the total project being defined and usually have an engineering or feasibility study associated with them.

- Semi-detailed Class 2 / 3 (the estimate is developed with unit costs and with assembly level line items) – these estimates are performed at 10 – 70% project definition have detailed engineering nearly complete and use bids tendered as development for the estimate.

- Detailed Class 1 (the estimate is developed with unit costs and with detailed bill of materials) – these estimates are performed at 50 – 100% project definition with the detailed engineering complete, bids tendered and verified to develop the estimate.

Mr. Atkins testified the 7-Year Plan provides the best estimate of the cost of the eligible improvements. He stated that the Plan includes the type of work that is core to NIPSCO's T&D business and much of the work was included in NIPSCO's 7-Year Electric Plan filed in Cause No. 44370. NIPSCO has extensive experience estimating and constructing projects of the type included in the Plan. Cost estimates for these projects have been based on NIPSCO's own experiences for similar work and recent experience executing this type of work. For added confidence, NIPSCO enlisted Burns and McDonnell to validate project estimates. Burns and McDonnell conducted site visits and produced construction estimates for many 2016 and 2017 projects that were then evaluated with NIPSCO cost estimates. The estimates produced by Burns and McDonnell and by NIPSCO were found to be within approximately 7% in total. Based on the estimates produced by Burns and McDonnell and NIPSCO and the comparison to actual costs of similar projects in recent years, it has been concluded that these are the best estimates for the projects included in the 7-Year Electric Plan. The Plan includes three types of projects: (a) discrete, single-unit projects ("Single Unit Projects"); (b) projects with multiple units to be completed in various locations ("Multiple Unit Projects"); and (c) Circuit Performance Improvement projects, which involve multiple units, but are not determined in advance of the year of the project. NIPSCO has provided estimates for all three types of projects:

- **Single Unit Projects** include Class 3 estimates for years 2016 and 2017 and Class 4 estimates for projects planned for years 2018 through 2022.

- **Multiple Unit Projects** include Class 4, or Parametric estimates, for all years. This is because Multiple Unit Projects are routine types of work such as pole replacement and cable replacement. Estimates for these projects were created using historical unit pricing based on actual costs incurred for the same type of work. It is appropriate to estimate in this manner because of the high number of individual projects, which makes it unnecessary to produce detailed estimates for each individual unit in the Plan. Based on historical cost performance the unit cost estimates for these Multiple Unit Projects for all 7-years of the Plan are considered to be Class 4 estimates.

- **Circuit Performance Improvement** projects are estimated similar to Multiple Unit Projects and include Class 4, or Parametric estimates, for all years. The difference, however, as I discuss above, is that Circuit Performance Improvement projects are determined annually based on the previous year's reliability data, rather than at the time of the filing of 7-Year Electric Plan. NIPSCO developed best estimates based on actual costs for similar projects for each year of the Plan (and escalated annually).

Mr. Atkins testified NIPSCO worked with a third party and developed the best estimate of the cost for each investment. Therefore, the estimates included are NIPSCO's best estimates as of the time of filing. The Company will continue to refine these estimates and provide the refined estimates in plan updates. Specifically, prior to the start of the new plan year, NIPSCO will provide at least Class 3 estimates for the next plan year for Single Unit Projects and Class 4 estimates for the next plan year for Multiple Unit Projects. In the appropriate tracker filing, NIPSCO will provide estimates for the Circuit Performance Improvement projects.

Mr. Atkins testified the various appendices of the Plan provide cost estimates for the projects included in the Plan. Appendices 1 and 2 of the 7-Year Electric Plan provide the asset registers for Risk Based and Deliverability and Condition Based Projects, respectively. This was the starting point for determining the annual list of projects and the estimated cost for completion of those projects. Appendix 3 and Appendix 4 of the 7-Year Electric Plan provide detailed cost estimates for the 2016 and 2017 projects, respectively. For projects with unit based estimates for 2016 and 2017 and for all projects to be completed in the out years of the Plan (2018-2022), NIPSCO has provided unit-cost based estimates broken down by direct and indirect costs including labor and material in Appendix 5 of the Plan.

Mr. Atkins explained how NIPSCO developed the direct capital cost estimates as follows:

- Single Unit Projects – the direct capital cost estimates for Years 1 and 2 (2016 and 2017) were developed by Burns & McDonnell and the Project Development Team utilizing detailed site reviews, internal expertise and outside engineering input. All estimates were reviewed by the NIPSCO engineering team. The project estimates for 2016 and 2017 are considered Class 3 estimates. The direct capital cost estimates for Years 3 through and 7 (2018 through 2022) were developed by the NIPSCO Engineering Team using historical unit cost data. Historical unit costs are applied to each project based on type of known scope. These project estimates are considered Class 4.

- Multiple Unit Projects – the direct capital cost estimates for all years of the Plan were developed by Burns & McDonnell and the NIPSCO Engineering Team using historical unit cost data. Historical unit costs are applied to each project based on type of known scope. Because no engineering had been completed at the time the estimates were prepared, these project estimates are considered Class 4. However, given the repetitive nature and the large number of projects, along with NIPSCO's experience with this type of work, there is a high level of confidence in these cost estimates.

Mr. Atkins explained how NIPSCO developed the indirect capital cost estimates. He stated that NIPSCO uses the most recent 12-month indirect rate history (indirect costs, excluding AFUDC, as a percentage of direct costs) and establishes a base indirect rate for the current year. The base indirect rate is then adjusted in the plan years, using a weighted average allocation by category to obtain the total indirect capital forecast for NIPSCO. The total indirect capital forecast starts with the prior year's total indirect capital actuals, excluding AFUDC, and is increased approximately 3% per year for inflation. The resulting adjusted rate is then applied to the direct capital cost for each year to arrive at the total indirect cost estimate.

Mr. Atkins explained how NIPSCO developed the estimated AFUDC for the investments. He stated that NIPSCO calculated AFUDC by multiplying the AFUDC Rate by the AFUDC Base by month. The forecasted AFUDC Rate is comprised of debt (2.3%) and equity (5.74%) components and uses the latest actual rates from the accounting department, which are updated every 6 months. The AFUDC Base includes direct capital, overhead and stores, freight & handling. The forecasted AFUDC Base is a monthly cumulative balance and consists of the prior period balance (if any), plus 50% of the prior period base additions, plus 50% of the current period base additions, minus the base reset (if any). The base reset reduces the AFUDC Base for assets that were included for recovery and starts the month new rates go into effect. For example, if NIPSCO filed on September 1 with a 90-day procedural schedule to recover TDSIC capital expenditures through June 30, the base reset would start on December 1 when new rates go into effect. Ultimately, the AFUDC estimate in the electric plan is a result of multiplying the AFUDC Rate by the AFUDC Base.

Mr. Atkins described how NIPSCO will manage the portfolio of projects included in the 7-Year Plan. He stated that the Engineering Department developed the 7-Year Electric Plan as well as the cost estimates for the projects. The portfolio of projects included in the 7-Year Electric Plan are then assigned to the Electric Projects and Construction Department for execution and management. The TDSIC Project Controls Team has the primary role of verifying that TDSIC project costs are accurately forecasted and accounted for. This includes obtaining, validating, tracking and paying invoices for the portfolio of projects included in the 7-Year Electric Plan. The TDSIC Project Controls Team is also responsible for creating monthly forecasts and accruals with input from the Electric Projects and Construction Department.

Mr. Atkins explained NIPSCO's cost management process as it relates to the projects included in the 7-Year Plan. He stated that the process for initiating a new TDSIC work order begins with the Project Engineer/Manager submitting a Capital Initiative Form ("CIF") to the TDSIC Support Budget Analyst. The Budget Analyst routes the CIF to the Plan Owner and the Project Execution Team for two levels of approval. The purpose of the first level of approval, termed "TDSIC Verification," is to verify that the project and costs are TDSIC eligible. This ensures that only eligible project costs are tracked via the TDSIC tracker. The Plan Owner approves projects for TDSIC eligibility by referring to NIPSCO's currently approved 7-Year Electric Plan. The Plan Owner is responsible for understanding the intent and purpose of the overall Plan, and reviews all requests to determine if the work is approved within the Plan. The Plan Owner also reviews new project requests to be added to the next Updated 7-Year Plan and determines if the project is an eligible improvement and necessary for purposes of system reliability and system modernization. This is a critical piece of the TDSIC Plan as it is allows the most flexibility for the utility as the system continues to change.

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

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

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

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

Mr. Atkins testified that while any plan has a degree of execution risk, steps have been taken and plans have been put in place to mitigate risk. It is important to realize, that while the investments in the Plan are substantial, NIPSCO has experience completing these type of projects. Safety is in the forefront as a design factor ensuring public safety and constructability. Safety is also an integral part of project execution to ensure projects are completed without injury to employees or contract partners. This is accomplished through training, onboarding and job site observations. For most projects, project scopes are detailed two years in advance utilizing standard designs improving estimate accuracy. A resource plan is developed on an annual basis, leveraging internal and contract resources with a heavy reliance on unit pricing whenever practical. Material and inventory needs are forecasted and integrated in the sourcing strategy focusing on price and volume commitment as well as product delivery and quality. These practices are used as a tool to better control commodity index price variations. Recognizing the Plan covers a 7-year period, it is not possible to completely mitigate increases in labor or commodities as market conditions change over time, but NIPSCO has taken appropriate steps to address these issues. He stated that effective project management processes and skills are important for efficient plan execution. NIPSCO has a Project Management Team with specific expertise in managing large projects and large scopes of work such a project groups. This team has been managing very similar projects over the past two years, gaining experience and expertise utilizing industry standard project management techniques to ensure safety, schedule, scope and cost.

Mr. Atkins testified that consistent with Ind. Code §8-1-39-9(a), NIPSCO plans to update the 7-Year Electric Plan in each tracker filing. He testified that in addition to the statutory requirement to update the plan, it is prudent and necessary for NIPSCO to systematically and periodically review, revise and update its Plan to respond to the dynamic nature of it its T&D system, customer demand, and equipment failures. While considerable analysis and thought went into the development of the 7-Year Electric Plan, it is important to note that the Plan is reflective of the characteristics of the electric system and the needs of NIPSCO's customers as they exist at the time the Plan was developed. As NIPSCO learns more in the upcoming years, the Plan will be updated. Over time, information is continually gathered around asset condition data. This information will be integrated into the risk model and will serve to modify the probability of asset failure. Additionally, configuration of the system, connectivity of critical customers, and other system events will serve to modify the consequence of failure driver in the risk model. As customer demands evolve, both from a location and utilization perspective, system deliverability requirements must evolve with them. Lastly, the 7-Year Electric Plan seeks to address risk by proactively replacing the riskiest elements in NIPSCO's system. Some elements of the system are best utilized in a "run to failure" mode while other elements may fail before their planned replacement cycle arrives. While the models utilized to develop the Plan are sound, it is impossible to perfectly predict the future. As such, when these emergent events occur, the Plan will be re-prioritized to address them. As such, a prudent 7-year plan must be dynamic. As information inputs change, the Plan will continue to be optimized to ensure the best plan possible is being deployed.

Mr. Atkins testified that as part of each tracker filing, NIPSCO will update its 7-Year Electric Plan, including updates to the asset registers (including the municipalities included in the streetlights replacement program), if appropriate, as well as the cost estimates. Based on industry standards and Company needs, NIPSCO will continually refresh both the risk model as well as the analysis associated with deliverability and condition based projects. Prior to the start of a new Plan year, NIPSCO will define the detailed project scopes and updated unit estimates for at least the next plan year, with the exception of Circuit Performance Improvement projects, which are planned at the beginning of the calendar year.

Mr. Atkins stated that NIPSCO contemplates the 90-day tracker filing procedural schedule would apply to new projects or changes to existing projects. However, NIPSCO recognizes it would not be appropriate to expect that a major modification to the 7-Year Electric Plan could be properly reviewed by the Commission and NIPSCO's stakeholders within the typical 90-day tracker filing procedural schedule. Some examples of a major modification would be the addition of a new project category (e.g. of distribution system-related software) or new types of equipment not represented within the 3,800+ major assets evaluated as part of the 7-Year Electric Plan (e.g., customer services). In addition, a serious natural or man-made disaster may also require a complete overhaul to NIPSCO's 7-Year Electric Plan which would not be possible to complete within the standard 90-day tracker filing procedural schedule. As such, NIPSCO proposes to work with its stakeholders on the appropriate way to review significant updates. Mr. Caister provides additional details on NIPSCO's proposal.

Mr. Atkins identified the incremental benefits attributable to the 7-Year Plan. He testified the 7-Year Electric Plan focuses on maintaining safe, reliable service for NIPSCO's customers in a cost effective manner. The Plan addresses all four types of eligible investment of safety, reliability, system modernization, or economic development included the TDSIC Statute. Although NIPSCO is not including any economic development projects at this time, NIPSCO is open to working with other parties to add appropriate economic development projects. The Plan's investments positively impact electric reliability, and safety, system modernization and economic development are also direct results. Reliability drivers include the avoidance of direct customer outages, the continuity of service when experiencing loss of system elements, compliance with NERC planning requirements for the Bulk Electric System, the ability to meet customer needs through deliverability during periods of high system stress, and the mitigation of potentially very long outages due to loss of system sources for extended periods of time.

Mr. Atkins testified NIPSCO has a large number of aging assets on its electric T&D system. The assets have aged naturally as a function of NIPSCO's service territory development over time and the natural life of the assets and many need to be replaced. The proactive replacement of aging infrastructure will help maintain the reliability of NIPSCO's electric T&D systems, which are growing older, and therefore riskier, with each passing year. The 7-Year Electric Plan address these replacements. In developing the 7-Year Electric Plan, NIPSCO carefully prioritized the list of planned investments to optimize the benefits of the investments to the extent possible. For risk-based projects, the Plan represents an optimized risk reduction of 30% versus a break-fix alternative.

Mr. Atkins explained that the proactive replacement of aging infrastructure also provides opportunities to replace old equipment with modern technology in a systematic and deliberate manner. System modernization brings benefits to NIPSCO's customers by enabling continued high reliability performance, and improving NIPSCO's capabilities to respond to an outage. By proactively managing the risks inherent in an aging system by implementing a risk-based long term replacement plan, NIPSCO will be able to avoid increasing levels of reactive or emergency work. Also, more modern system protection devices which are included in the Plan provide for faster clearing of system faults which will protect the asset lives of expensive system equipment and minimize outage scales.

Mr. Atkins testified safety is of utmost importance to NIPSCO and the public. NIPSCO's 7-Year Electric Plan enables a safe electric system, both for the customers served, as well as NIPSCO's operations and maintenance work force that keeps the system running day in and day out. NIPSCO sets a high standard for the safety of its workforce and the public. Maintaining high safety performance is not only an objective of NIPSCO's Plan, but a requirement for its workforce and its customers. He testified the continued safety of NIPSCO's employees and customers is enhanced and potential damage to other electric system components is avoided when the risks of violent failures (i.e. explosions, fires, downed power lines) are mitigated. Lastly, the extension of new facilities or the rebuilding of older facilities almost always provides for a more robust system to meet system delivery or interconnection requirements.

Mr. Atkins testified that in addition to providing continued safe and reliable service, NIPSCO's Plan allows for planned replacement of electric assets, realizing construction efficiencies versus replacement in unplanned (emergent) conditions and premium labor rates for emergent replacements are mitigated. In addition, the planned replacement of assets should decrease the premiums that are sometimes required to expedite the manufacture of long lead time items, such as transmission transformers and breakers.

Mr. Atkins testified the Plan fosters economic development. A key benefit of the long term plan is the economic development spurred by these investments in the electric system. As Mr. Caister discusses more fully, the Economic Impact Report prepared by Black &Veatch shows the positive economic impact of these investments to Northern Indiana. In addition, the streetlights investments offer benefits by improving photometrics, providing system modernization, and enhancing the quality of life of the citizens of the individual municipalities, as well as reducing streetlight energy consumption. Finally, to the extent a future economic development investment is identified and supported by another party, NIPSCO would present the proposed project as part of an updated plan and seek a determination of TDSIC eligibility.

Mr. Atkins testified the estimated costs of the eligible improvements included in the 7-Year Electric Plan are justified by the incremental benefits. The Plan contains solutions that will enhance customer and employee safety, avoid outages, preserve operational and planning contingencies, provide superior equipment protection, and meet evolving customer demands. By virtue of achieving all of these benefits in a thoughtful, planned and cost efficient manner, the Plan provides incremental benefit for NIPSCO's customers.

5. **Overview of the Settlement.** Following the submittal of NIPSCO's case-in-chief testimony, the Settling Parties filed notice that they had reached a settlement of all issues. The key terms of the Settlement are summarized as follows:

- The Settling Parties agree that the Commission should approve, as "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code ch. 8-1-39 (the "TDSIC statute"), the projects set forth in NIPSCO's 7-Year Electric Plan (the "T&D Plan"), consisting of capital expenditures of up to $1.33 billion (includes direct capital, indirect capital and allowance for funds used during construction ("AFUDC")) over the 7-year period from 2016 through 2022; however, the Settling Parties agree that a maximum of $1.25 billion of direct capital, indirect capital, and AFUDC (collectively "Approved T&D Plan Costs") shall be eligible for the TDSIC ratemaking treatment.

- The Settling Parties agree that NIPSCO has provided detailed project descriptions for the T&D Plan, as well as sufficient cost estimates for the projects, as would support a Commission finding that the T&D Plan is reasonable and in the public interest, that the Approved T&D Plan Costs are justified by the benefits of the plan, and that the estimates summarized on Petitioner's Exhibit No. 2, Attachment 2-A reflect the best estimates of the T&D Plan costs.

- The Settling Parties agree that NIPSCO should be granted authority to defer as a regulatory asset all TDSIC Costs (as defined in Ind. Code § 8-1-39-7) associated with the Approved T&D Plan Costs that are incurred from January 1, 2016 and subsequent to the issuance of an Order in this proceeding until such amounts are recovered through rates.

- NIPSCO has agreed to limit recovery through the TDSIC ratemaking treatment of its capital costs actually expended under its T&D Plan up to $1.25 billion over the 7-year TDSIC.

- The Settling Parties agree that NIPSCO will remove $80 million of capital expenditures from the TDSIC ratemaking treatment. The Settling Parties request that the Commission approve all projects included in the T&D Plan and that NIPSCO be authorized to use any project included in its $1.33 billion T&D Plan to comprise the up to $1.25 billion in total plan capital expenditures over the 7-year period.

- The Settling Parties agree that NIPSCO's annual spend for TDSIC capital costs should be capped at $5 million less than currently projected for Years 1 and 2 (2016 and 2017), $10 million less than currently projected for Year 3 (2018), and $15 million less than currently projected for Years 4, 5, 6 and 7 (2019 through

2022).

- The Settling Parties agree that the Approved T&D Plan Costs eligible for TDSIC ratemaking treatment will not exceed $1.25 billion. NIPSCO shall have the ability to deviate above each annual cost recovery cap by no more than 5% in a rolling historical three-year period. Any amount below the annual cap in a given year may be rolled over as an increase to the cap for the following years within the three-year rolling period. Any amount above the annual cap in a given year will operate as an offset to the available cap variance for the following years within the three-year rolling period.

- The Settling Parties agree that the overall composition of the projects included in the T&D Plan will be maintained at 61 percent distribution projects and 39 percent transmission projects, plus or minus one percent.

- NIPSCO shall be authorized to implement components of the T&D Plan in good faith up to the $1.25 billion cap over a seven-year period, as outlined herein, but shall have the flexibility to adjust the T&D Plan as circumstances dictate, including but not limited to system changes, reliability issues, or reasonable and prudent cost changes.

- Each year in its fall tracker filing, NIPSCO will provide a detailed list of projects for the upcoming year, with best estimate of project costs, but NIPSCO retains the ability to move projects between years as appropriate. If a project is rescheduled to a different year, the annual caps for the affected years will be adjusted by the approved cost estimate for that project. Each year in its spring tracker filing, NIPSCO will provide the actual costs of the projects completed in the prior year and updated projected costs of the projects in the following years.

- The Settling Parties each reserve the right to take any position with respect to any new project proposed by NIPSCO for inclusion in the T&D Plan in a future TDSIC tracker proceeding, but recovery of a maximum of 80% of incurred costs associated with the $1.25 billion in capital expenditures through the TDSIC Rider, and deferral of 20% of such costs for recovery in a future base rate case shall not be adjusted.

- The Settling Parties agree to inclusion of up to $3.5 million for an Economic Development project for the LaPorte County Kingsbury Industrial Park ("Kingsbury Project") including a $2.5 million project for substation upgrades as provided for in the proffered Settlement Agreement submitted in NIPSCO's pending rate case in Cause No. 44688 (the "Rate Case Settlement")[4] and up to $1.0 million for other distribution infrastructure upgrades.

- The Settling Parties agree that the first tracker filing associated with the approved

[4] The Settling Parties in this case are also signatories to the proposed Settlement Agreement in Cause No. 44688.

T&D Plan shall occur on or about July 1, 2016 to establish factors for the first portion of 2016 which shall be implemented with the first billing cycle starting February 1, 2017. The second such tracker filing shall be made on or about July 1, 2017, with rates to be effective with the first billing cycle of October 2017 consistent with the statutory 90-day cycle. Subsequent tracker filings would occur semi-annually each February and August thereafter.

- The Settling Parties agree to NIPSCO's proposed implementation of a TDSIC mass retrofit LED Streetlight project for NIPSCO-owned streetlights based on Requests for Proposals ("RFP") seeking competitive bids for the procurement and for the installation of LED streetlight fixtures subject to certain ratemaking treatment. This includes the finalization of mass retrofit LED rates in the TDSIC tracker process after the LED capital costs are finalized from the competitive RFPs.

- The Settling Parties agree to various ratemaking terms as further discussed in the testimony in support of the Settlement.

6. **Testimony in Support of the Settlement.**

A. NIPSCO Witness Caister. Mr. Caister provided (1) support for the agreed-to requested deferral authority; (2) support for the $1.25 billion cap proposed in the Settlement; and (3) an explanation of why the Settlement is in the public interest. Mr. Caister summarized the difference between NIPSCO's proposed plan costs and those agreed to in the Settlement ("Approved T&D Plan Costs"). He stated that in its original filing in this Cause, NIPSCO's proposed plan consisted of capital expenditures of up to $1.33 billion, which included direct capital, indirect capital and allowance for funds used during construction ("AFUDC") over the 7-year period from 2016 through 2022. The Settling Parties agreed that the Approved T&D Plan Costs would be limited to a maximum $1.25 billion of direct capital, indirect capital and AFUDC. This is a reduction of $80 million in capital expenditures from TDSIC ratemaking treatment. Furthermore, the Settling Parties agreed that NIPSCO's annual spend for TDSIC capital costs should be capped at $5 million less than currently projected in Years 1 and 2 (2016 and 2017), $10 million less than currently projected for Year 3 (2018), and $15 million less than currently projected for Years 4, 5, 6 and 7 (2019 through 2022). The proposed plan versus T&D Plan Costs per the Settlement are shown in the table below.

	2016	2017	2018	2019	2020	2021	2022	Total
	(in millions)							
Proposed Plan	$140.8	$117.2	$170.3	$224.1	$224.6	$228.8	$226.3	$1,332
T&D Plan Costs – Per Settlement Agreement	$135.8	$112.2	$160.3	$209.1	$209.6	$213.8	$211.3	$1,252

Mr. Caister testified the Settlement does not call for NIPSCO to identify particular projects that were included in the plan as filed but will be cut under the agreed-cap. He stated all of the projects included in the T&D Plan will be designated as eligible for TDSIC treatment and as the Settlement provides, it is NIPSCO's expectation to complete substantially all of the planned projects by the end of the 7-year period. The overall cap and the annual caps will limit the capital expenditures subject to TDSIC ratemaking treatment, but will not alter the scope of work that NIPSCO plans to complete.

Mr. Caister described the rationale for the agreed upon Approved T&D Plan Costs. He stated there is a balancing of interests among NIPSCO's stakeholders. All want to assure NIPSCO's ability to provide safe and reliable service at just and reasonable rates. The Settlement reflects the Settling Parties' desire to allow NIPSCO to pursue an appropriate level of infrastructure system improvement projects while providing protections to ratepayers, including an overall cap to be included in the plan, which provides certainty regarding cost recovery for the duration of this plan.

As to the annual cap, Mr. Caister testified that because of the way NIPSCO's projects are planned, managed and executed, it is nearly impossible to schedule expenditures that match exactly the hard cap for each year of the T&D Plan. Recognizing that, the Settling Parties agree that NIPSCO should have the ability to deviate above each annual cost recovery cap by no more than 5% in a rolling historical three-year period. If NIPSCO does not spend up to the cap in a particular year, the remaining amount may be rolled over as an increase to the cap in the following years within the three year rolling period. The Settlement provides two examples of the operation of the 5% deviation within the three-year rolling period. However, for purposes of TDSIC ratemaking treatment, under no circumstances is NIPSCO allowed to deviate from the overall cap of $1.25 billion. In addition, the Settling Parties agreed that if a given project is rescheduled in whole or in part to a different year, the annual caps for the affected years will be adjusted to reflect the reduction or addition of the approved estimate for that project. The parties and the Commission also retain the ability to review any costs in excess of approved estimates in accordance with Ind. Code §8-1-39-9(f).

Mr. Caister described NIPSCO's request to defer the TDSIC costs associated with its Approved T&D Plan Costs. He explained that when we speak of deferral authority – there are two different deferral buckets. There is the 20 percent deferral bucket that includes 20 percent of the TDSIC Costs until the utility's next rate case, as provided in Ind. Code 8-1-39-9(b). The second bucket is the authority to defer the Approved T&D Plan Costs up to the $1.25 billion cap on an interim basis from the time they are incurred until the time they are recovered in NIPSCO's retail electric rates. The Commission has authority to approve such interim deferrals consistent with Ind. Code §§ 8-1-2-12 and 14. The interim deferrals will be recorded in Account 182.3, Other Regulatory Assets, and will be amortized over the number of months included in the recovery period of NIPSCO's tracker filing.

Mr. Caister provided an overview of the Settlement's provisions regarding Economic Development projects. He stated that there are two provisions related to economic development. First, the Settling Parties agree to inclusion of an Economic Development project for the Kingsbury Project at a cost of $3.5 million. Any capital expenditures from the Kingsbury project will be presented in a tracker filing by NIPSCO and LaPorte County, which should provide a sufficient evidentiary showing consistent with and required by Ind. Code Ch. 8-1-39 for the approval of any such expenditures.[5] Second, the Settling Parties have agreed that any approved Economic Development projects during the term of the T&D Plan will not be included in the $1.25 billion capital cost cap.

Mr. Caister testified that given the current struggles of Indiana's manufacturing sector, NIPSCO recognized the need to work to encourage appropriate and viable economic development in its state. The Settlement provisions balance the interests of all stakeholders. The Kingsbury Project will be undertaken once the details are known and sufficient evidence has been provided for the Commission. This provides an appropriate process and mechanism for the Commission and other stakeholders to evaluate the merits of the Kingsbury Project and any necessary upgrades. Similarly, allowing NIPSCO, with Commission approval, to add economic development projects without impacting the recoverable investment available for the other projects in the T&D Plan allows NIPSCO to pursue system modernization and economic development concurrently. NIPSCO supports economic development initiatives and the job creation that results from beneficial and successful efforts, including such initiatives of LaPorte County and others. The Settlement provides for the inclusion of this economic development project for the Kingsbury Industrial Park infrastructure upgrades, and supports inclusion, when appropriate, in a subsequent tracker proceeding.

Mr. Caister summarized the Settlement as it pertains to NIPSCO's proposed Streetlighting project. He stated that in its case-in-chief, NIPSCO requested the inclusion of $16.7 million over the 7-years of the Plan to replace all of NIPSCO's company-owned high pressure sodium streetlights with light emitting diode ("LED") lights. As part of this proposal, the revenue requirement (on a per lamp basis) associated with the installed cost of the lights ("Installed Cost") would be included in the TDSIC tracker, with streetlight customers continuing to pay the remaining components of the streetlighting tariff rate (i.e. fuel and energy expense; customer and demand costs; and operations and maintenance expense) as approved in NIPSCO's pending base rate case (Cause No. 44688). As part of the Settlement, unlike other TDSIC capital additions, the Settling Parties agreed that 50% of the Installed Cost should be included in a streetlight lamp rate applicable to each fixture as part of NIPSCO's mass retrofit streetlights tariff rate. The remaining 50% of the installed cost will be recovered as TDSIC Costs through the TDSIC tracker. To determine the Installed Cost, NIPSCO has agreed to conduct requests for proposals ("RFPs") seeking competitive bids for the LED fixtures as well as for the installation. NIPSCO will solicit input from interested municipalities on the language, terms and a list of recipients for the LED procurement and installation RFPs with the intent to make them as broad and as competitive as reasonably possible to obtain the lowest bids reasonably possible, from qualified contractors, thereby minimizing the capital costs of the TDSIC LED mass retrofit program. It is important to note that, after reviewing the results of the RFP and discussing with the interested municipalities, NIPSCO may also determine internal labor is the most reasonably priced source for installation of the fixtures. NIPSCO will collaborate with interested municipalities on the selection of LED procurement and installation contractors (including the potential of NIPSCO's internal labor resources if appropriate). To the extent municipalities and

[5] A $2.5 million project was provided for and is pending as part of the Rate Case Settlement, with up to an additional $1 million expenditure in the instant docket for economic development for other distribution system upgrades.

NIPSCO find it beneficial, NIPSCO and interested municipalities may combine orders for LED lights or submit orders concurrently for the purpose of mutual cost savings.

Mr. Caister described the ratemaking treatment in the Settlement as follows:

- The Settling Parties agree that NIPSCO has the authority to apply CWIP ratemaking treatment to all transmission, distribution, and storage system improvements associated with the Approved T&D Plan Costs through the TDSIC mechanism. This is consistent with the treatment of CWIP in NIPSCO's previous Electric TDSIC (as approved by the Commission in Cause No. 44370) as well as in NIPSCO's current Gas TDSIC (as approved by the Commission Cause No. 44403). The Settlement prevents NIPSCO from seeking CWIP treatment of costs in excess of the $1.25 billion included in the Approved T&D Plan Costs.

- The Settling Parties agree that NIPSCO shall continue to recover 80% of TDSIC Costs associated with the Approved T&D Plan Costs through Rider 688 or successor TDSIC Rider(s) as approved by the Commission. This is the same recovery mechanism established in and approved by the Commission in Cause No. 44371, NIPSCO's previous Electric TDSIC and is consistent with the Indiana Code § 8-1-39-9.

- As was approved by the Commission in Cause No. 44371, the Settling Parties agree that NIPSCO will defer, as a regulatory asset, ongoing carrying charges based on the weighted cost of capital on all deferred TDSIC Costs associated with the Approved T&D Plan Costs until the deferred TDSIC Costs are included for recovery in rates.

- The Settling Parties have agreed that NIPSCO will adjust its authorized net operating income to reflect any approved earnings associated with TDSIC for purposes of Ind. Code §8-1-2-42(d)(3) pursuant to Ind. Code § 8-1-39-13(b). This is consistent with the earnings test treatment approved by the Commission in Cause No. 44371.

- The Settling Parties agree that the capital structure used to calculate the weighted average cost of capital ("WACC") will reflect the components approved by the Commission in NIPSCO's currently-pending rate case (Cause No. 44688). This includes, but is not limited to, debt, equity, prepaid pension asset and deferred income. The use of the WACC as approved in the most recent rate case is consistent with the capital structure treatment approved in Cause No. 44371. It is anticipated that NIPSCO will have a final order in Cause No. 44688 prior to the first TDSIC factor going into effect with the first billing cycle starting in February, 2017.

- As previously approved by the Commission and affirmed by the Indiana Court of Appeals in Cause Nos. 44370 and 44371, the Settling Parties agree that NIPSCO will continue to calculate the aggregate increase in its total retail revenue attributable to the TDSIC to determine whether the TDSIC will result in an average aggregate increase of more than 2% in a twelve month period.

- The Settling Parties agree that the return on equity for the TDSIC Rider will be 9.975%, which is the amount included in the Rate Case Settlement. NIPSCO acknowledges that if the Rate Case Settlement is approved, the provision in the Rate Case Settlement calling for at least 60% debt financing shall be applicable to the capital projects in the T&D Plan in the aggregate. NIPSCO will report on compliance with regard to this debt financing requirement in each financing petition filed with the Commission.

- The Commission approved and the Court of Appeals affirmed in Cause Nos. 44370 and 44371 that there will be no netting in the TDSIC Rider of depreciation or return. Therefore, the depreciation expense and/or return associated with retired and replaced equipment will not be netted against the depreciation expense and/or return associated with new equipment in the TDSIC Rider, and base retail rates will not be adjusted for these items.

- In compliance with the TDSIC Statute, the Settling Parties agree that the allocation factors used in NIPSCO's TDSIC Rider shall be those as approved by the Commission in Cause No. 44688, NIPSCO's pending base rate case. If the Commission does not approve the Rate Case Settlement in its entirety along with the TDSIC Allocation, the Rate Case Settlement shall be null and void and deemed withdrawn, upon notice in writing by any Settling Party within fifteen (15) business days after the date of the Final Order that any modifications made by the Commission are unacceptable to it. The allocation factors for the TDSIC Rider that are proposed in NIPSCO's pending base rate case are consistent with cost causation principles and provide for the allocation of transmission and distribution costs in a manner consistent with those principles. It is anticipated that NIPSCO will have a final order in Cause No. 44688 prior to the first electric TDSIC factor going into effect (February, 2017).

- NIPSCO made no commitments regarding the timing of its next base rate case as part of the Settlement. However, the Settling Parties agree that transmission and distribution improvements in-service by the rate base cut-off date will, subject to a normal prudence review in the TDSIC Rider proceedings, be included in rate base and NIPSCO's new base rates. After a final order is approved in a subsequent base rate case, the TDSIC Rider will be subject to the return on equity and allocation factors approved by the Commission in such case. The 20% of the transmission and distribution improvements associated with the T&D Plan that have been deferred with carrying costs will also be included in retail rates and rate base in such subsequent rate case. The Settling Parties agree that, if a final order is approved in a base rate case during the term of the T&D Plan, all recovery caps agreed upon in the Settlement will remain in effect for the 2016-2022 time period unless NIPSCO receives approval from the Commission for a new TDSIC Plan.

Mr. Caister provided a background for this proceeding. He stated that NIPSCO filed its first electric TDSIC plan in July 2013. After the Commission approved the plan, various parties appealed, and the Court of Appeals entered an order finding that NIPSCO's initial 7-year plan lacked detail regarding years two through seven and remanded the proceeding back to the Commission. Various parties subsequently filed a global settlement agreement, which the Commission approved in relevant part, which provided that NIPSCO could recover, through general rate cases, deferred TDSIC costs incurred in 2014 and 2015 and that NIPSCO would file a new 7-year plan for years 2016-2022. This proceeding involves that subsequent 7-year plan.

He testified the Settlement comprehensively addresses NIPSCO's T&D Plan and provides a roadmap for resolution of issues that have been the subject of proceedings for three years. Ultimately, the Settlement falls within the broader public interest by providing all customer segments with a reasonable outcome and providing NIPSCO a solid foundation from which it can invest in Northern Indiana's energy infrastructure and help fuel job creation and economic growth.

Mr. Caister commended the efforts of all Settling Parties that led to the Settlement in the abbreviated time permitted by the TDSIC Statute. The Settlement was only possible because of the collaborative and open efforts of all Settling Parties. He testified that Citizens Action Coalition ("CAC") was invited to participate in settlement negotiations and attended two settlement meetings, although in the end, the Settling Parties were not able to reach agreement with CAC.

Mr. Caister testified all of the provisions of the Settlement are interrelated. He stated the Settlement represents a diligent effort by all Settling Parties to reach a comprehensive result. The complexity of the issues and the diversity of the Settling Parties dictated the need for compromise on the part of everyone involved, and the Settlement reflects a delicate balance that accommodates the interests of all Settling Parties in a reasonable way.

Mr. Caister testified approval of the Settlement as it is written is consistent with the public interest because the Settlement represents a comprehensive resolution of all of the issues in this proceeding by NIPSCO and the Settling Parties. As the evidence reflects, the Settlement resolves complex, divisive, and controversial issues. The Settlement balances the interests of NIPSCO with those of its customers without the expense and risk of continued litigation and likely appeal. Moreover, the Settlement provides NIPSCO with an opportunity to earn a reasonable return on the investment it has made, balanced with the interests of NIPSCO's customers in receiving reasonable service at a fair cost.

Mr. Caister testified time is of the essence to have the Settlement considered and approved by the Commission, and the Settling Parties have agreed to request that the Commission review the Settlement on an expedited basis, and if it finds the Settlement is reasonable and in the public interest, approve it without any material changes as quickly as possible, but in no event later than July 27, 2016. While the Settling Parties appreciate that the Commission has a responsibility to carefully consider the evidence of record to determine whether the Settlement is in the public interest, all Settling Parties request the Commission to do so as soon as possible, consistent with the timing requirements of the TDSIC Statute.

B. <u>OUCC Witness Rutter</u>. Edward T. Rutter, Utility Analyst in the Resource Planning and Communications Division of the OUCC, supported the terms of the Settlement stating that while the Settlement is the result of a compromise reached among the Settling Parties on the issues presented in this case, it is nonetheless beneficial to ratepayers' interests when examined in its entirety and should be approved by the Commission as being in the public interest. He testified there are a number of ratepayer benefits achieved by the Settlement. First, a reduction to the proposed 7-Year Plan capital costs of $1.33 billion by approximately $80.0 million, with the remaining $1.25 billion of capital expenditures under NIPSCO's TDSIC Plan eligible for cost recovery through NIPSCO's TDSIC tracker are capped at that amount for the term of the Plan. Further, the Settlement outlines the specific allocation of the $80 million reduction to each year of the 7-Year Plan. Second, a mass replacement of NIPSCO-owned streetlights with energy efficient LED lighting throughout NIPSCO's electric service territory. He stated that consistent with NIPSCO's proposal in its case-in-chief, replacement of NIPSCO-owned streetlights will be prioritized in municipalities that have responded to NIPSCO's RFP indicating interest in replacing city-owned lighting with LED lamps. He testified the Settlement also resolves the issue of the LED mass retrofit rate that municipalities should pay for each LED lamp, consistent with the terms of the Rate Case Settlement. He stated the cost of an LED lamp, as determined by a competitive bid process, will be shared equally between the lamp charge included in NIPSCO's LED mass retrofit tariff rate and the revenue requirement associated with NIPSCO's proposed 7-Year Plan. Third, the Settlement provides for a 9.975% return on common equity for eligible plan investments and up to $3.5 million for an economic development project at Kingsbury Industrial park in LaPorte County.

Mr. Rutter testified the terms of the Settlement meet the requirements of Ind. Code § 8-1-39-10 ("Section 10 Proceeding") and the requirements established by the Indiana Court of Appeals' decision in Cause Nos. 44370 and 44371, issued on April 8, 2015 ("Appellate Order"). He testified NISPCO provided detailed project and program descriptions for its 7-Year Plan, including detailed engineering analyses, and cost estimates for the projects and programs. He stated NIPSCO's level of support for the 7-Year Plan provides sufficient specificity to support Commission Findings and an Order in this Section 10 Proceeding that the public convenience and necessity require the eligible improvements outlined in NIPSCO's 7-Year Plan; that the estimates summarized on Petitioner's Exhibit No. 2, Attachment 2-A reflect the best estimates of the 7-Year Plan costs; and that the 7-Year Plan is reasonable and should be approved. He concluded the proposed 7-Year Plan meets the requirements established in the Appellate Order.

Mr. Rutter testified the terms of the Settlement describe how the costs of NIPSCO's 7-Year Plan will be reduced. He stated that while NIPSCO provided sufficient support for the $1.33 billion in projects and programs proposed to be included in its 7-Year Plan, for purposes of settlement, the Settling Parties agreed that that total cost of the 7-Year Plan will be capped at $1.25 billion, representing a reduction of $80 million eligible for TDSIC cost recovery. He stated the Settlement also provides for a specified allocation of the $80 million reduction over each year of the 7-Year Plan. He noted that while the costs associated with NIPSCO's 7-Year Plan cannot exceed $1.25 billion, the Settling Parties agreed that NIPSCO has the ability to deviate above each annual cost recovery cap by no more than 5% in a rolling historical three-year period.

Mr. Rutter testified the Settling Parties agreed that while NIPSCO is authorized to implement components of its 7-Year Plan in good faith up to the $1.25 billion cap, NIPSCO has the flexibility to adjust the Plan as circumstances may dictate. He stated those circumstances may include system changes, reliability issues, or reasonable and prudent cost changes. He noted the Settlement describes such flexibility, stating that in the event a given project, in whole or in part, is rescheduled to a different year, the annual cost recovery caps for the affected years will be adjusted by that project's whole or partial approved cost estimate to reflect the change. He testified the Settling Parties also agreed that NIPSCO will provide certain documentation to justify cost variances in excess of agreed thresholds, and that the non-NIPSCO Settling Parties retain the ability to challenge any costs that exceed the approved estimates.

With regard to the inclusion of NIPSCO's proposed LED streetlight replace project, Mr. Rutter testified the Settlement contains specific provisions that describe how the replacement of NIPSCO-owned streetlights within its service territory with energy efficient LEDs will be incorporated into its 7-Year Plan as well as how the costs of the LED lamps will be allocated between the LED mass retrofit rate included in NIPSCO's tariff and the TDSIC revenue requirement to flow through the TDSIC tracker. He explained that in the Rate Case Settlement, the parties agreed that NIPSCO would add a placeholder in its tariff for the LED mass retrofit rate that was subject to approval in its TDSIC filings. He stated that in this proceeding the Settling Parties have agreed to NIPSCO's proposed implementation of a TDSIC mass retrofit rate LED Streetlight project for NIPSCO-owned streetlights. He explained that to implement the LED Streetlight project, NIPSCO will conduct RFPs seeking competitive bids for the procurement and installation of LED streetlight fixtures to be installed pursuant to the Settlement and NIPSCO's 7-Year Plan. The Settlement provides the per LED unit capital cost components will be finalized after the contractor responses to the RFPs for mass LED purchase and mass installation contracts are received and the contracts are negotiated and finalized. He stated that upon selection of qualified bidders for LED supply and installation and the submission of an updated, estimated cost of the mass retrofit LED Streetlight project, per the Settlement terms 50% of the estimated revenue requirement (on a per lamp basis) associated with the installed cost shall be included in the streetlight lamp rate applicable to each fixture as part of NIPSCO's tariff rate. He testified the Settling Parties have agreed that the remaining 50% of the estimated revenue requirement (including all variances associated with the revenue requirement for all actual installed cost of the mass LED Streetlight project through the 7-Year Plan) shall be recoverable as approved TDSIC Costs as that term is defined in the TDSIC Statute (IC 8-1-39-7) through NIPSCO's TDSIC Rider.

Mr. Rutter testified the Settlement reflects a balance of all interests among the Settling Parties. He stated that given the number of benefits provided to ratepayers as outlined in the Settlement and discussed herein, the OUCC, as the statutory representative of all ratepayers, believes the Settlement is in the public interest, is supported by sufficient evidence, and therefore should be approved in its entirety.

C. <u>Industrial Group Witness Phillips</u>. Nicholas Phillips, Jr., a consultant in the field of public utility regulation and Managing Principal of Brubaker & Associates, Inc., on behalf of Industrial Group, explained Industrial Group's interest in the Settlement. He stated members of the Industrial Group take service under Rates 624, 632, 633 and 634, make up over 40% of NIPSCO's sales. Furthermore the members of the Industrial Group employ 12,000 people in Northwest Indiana and as such are some of the largest employers in the NIPSCO service area and their economic viability has a ripple effect on NIPSCO's commercial and residential customers as well. He noted that many of the smaller industrial and commercial businesses in NIPSCO's service area are dependent on the viability of NIPSCO's large industrial customers. He stated members of the Industrial Group are engaged in operations that are highly energy-intensive, so that energy costs are a major component of production costs. Thus, keeping the large industrial customers' operating costs competitive in Northwest Indiana is vital to keeping the existing customers there and attracting new industry.

Mr. Phillips recommended approval of the Settlement which is based on appropriate regulatory policy and sound ratemaking principles. He testified the Settlement reflects a comprehensive agreement that resulted from arms-length negotiations between the Settling Parties. Mr. Phillips testified the Settlement should be approved because the Settlement (1) is fair, reasonable and in the public interest; (2) mitigates the increase to all classes of customers from NIPSCO's filed position; (3) minimizes the risk of cost increases and contested issues in future TDSIC filings; and (4) provides a TDSIC framework which provides consumer protections over the course of NIPSCO's 7-Year Plan.

Mr. Phillips provided some relevant background information with regard to TDSIC. He stated the TDSIC Statute has presented many issues of first impression and groups of industrial customers have been actively involved in determining how the law should be implemented. Specifically, he noted that NIPSCO Industrial Group was involved in Cause Nos. 44370 and 44371 and raised concerns which led to the Court of Appeals decision in *NIPSCO Industrial Group v. NIPSCO*, 31 NE3d 1 (Ind. Ct. App. 2015). He stated that industrial customers reached an agreement with NIPSCO and the OUCC on remand from the Court of Appeals. He stated that industrial customers have also participated in NIPSCO's Gas TDSIC cases, which have been actively litigated. Mr. Phillips testified that by reaching the current Settlement, the Settling Parties present a 7-Year Plan which is anticipated to produce a more streamlined process.

Mr. Phillips testified NIPSCO's 7-Year Plan differs from what it filed in Cause No. 44370. He stated as part of its filed case in this proceeding, NIPSCO provided asset registers identifying specific projects it intends to undertake by year and estimated cost. He noted the only project without an asset register is the circuit performance program, although NIPSCO has proposed ascertainable standards for that work.

Mr. Phillips testified to the benefits of the Settlement. He stated the Settlement reduces the TDSIC eligible capital expenditures by $80 million over the TDSIC period and, equally important from a ratemaking standpoint, the TDSIC tracker is capped in the amount it can track in each individual year, with a slight tolerance from year to year. He testified that under the Settlement NIPSCO commits to complete substantially all of the projects within the next 7 years. Accordingly, NIPSCO cannot manage to the cap by eliminating projects from its 7-Year Plan. In addition, if actual costs exceed NIPSCO's cost estimates, stakeholders retain the right to challenge cost overruns under Ind. Code § 8-1-39-9(f).

Mr. Phillips testified the Settlement provides for a specific schedule for implementing a TDSIC tracker based on an approved 7-Year Plan. He noted that knowing the timing of tracker charges assists industrial customers in being able to budget and plan for increases in electric costs.

Mr. Phillips testified the Settlement beneficially builds on the agreed rate case resolution by using a reduced return on equity of 9.975% and the cost allocation factors from Cause No. 44688, which reduces contested issues in future tracker proceedings. He stated the TDSIC cost allocation factors are based on the revenue requirement for the transmission and distribution functions appropriately allocated to classes by the cost of service study in Cause No. 44688, which are consistent with and reflective of cost of service.

Mr. Phillips testified the Settlement, when taken as a complete package, reasonably resolves the Industrial Group's issues in this case and results in a fair and reasonable resolution. He stated the Settlement reduces the impact of NIPSCO's 7-Year Plan for all classes, provides ratepayer protections over the 7-years of NIPSCO's 7-Year Plan, while providing NIPSCO some reasonable flexibility in managing the construction of the projects within the Plan. He testified the Settlement is a comprehensive agreement and each term within the Settlement is essential to the overall reasonableness of the agreement. Mr. Phillips recommended the Commission approve the Settlement without any material changes.

D. LaPorte Witness Decker. Dave Decker, Board President of LaPorte, testified how critical it is for NIPSCO to make proper investments in electric infrastructure in LaPorte County to assist in its ongoing economic development initiatives. He shared that he has been serving on the Board of County Commissioners since 2013 and in 2015 was elected Board president. He stated that one of the first acts of the Board after he took office was to establish a LaPorte County Office of Economic Development to assist developers and industrial prospects looking for available site development, tax incentives, zoning and other items needed to assist job growth. He stated a key focus for the County since January, 2013 has been on bringing to fruition major development for the Kingsbury Industrial Park which lies five miles south of LaPorte, Indiana.

Mr. Decker noted that the Kingsbury Industrial Park is a very large geographic area taking up much of Washington Township in LaPorte County. The area used to be a World War II ordnance plant that employed up to 30,000 workers during the height of the war, manufacturing munitions for the war effort. He explained that after the war, it was converted to an industrial park and has had some success in attracting small-scale manufacturing. He noted that key to jump-starting large scale development was a railroad spur that has recently been completed into the Industrial Park. He stated LaPorte County also committed a $6 million loan from Major Moves monies. He noted that the Park has two Class I rail carriers whose lines run into the Park. LaPorte County's plans include bring large trans-shipping operations to the industrial park.

Mr. Decker stated while the county has been successful in landing smaller operations in the Park, it is still looking to land larger transloading operators. One significant key is upgrading the infrastructure at the Park, which is why this proceeding and commitment by NIPSCO is so important.

Mr. Decker also discussed recent developer announcements of plans for a freight rail bypass around the congested Chicago market that would run from Wisconsin and have Kingsbury Industrial park as its terminus. He noted that while planning for this newest rail line is just now undergoing the environmental review process, the fact that developers believe running a freight rail bypass right into Kingsbury Industrial park as its terminus, means the

County is on the right track with this park's potential. He stated that not only is Kingsbury Industrial Park listed as CSX Railroad's only Select Site in Indiana, it is one of the few CSX Select Sites in the Midwest.

Mr. Decker expressed concerns about the ability of the current Kingsbury Industrial Park electric infrastructure to handle large scale development. He stated one of the issues raised by site selectors with Project Lyre was the aging electric infrastructure. He noted that when site selectors came to Indiana, he had a chance to visit with them and a concern raised included the inadequacy of the substation located at Kingsbury Industrial Park as well as most of the distribution system has not been upgraded since World War II. Mr. Decker pointed out the fact that most of the poles, wires and insulators in the industrial park are original construction in 1942. He stated that because of the aging condition of the poles, wire and insulators, there are periodic outages in the Park.

Mr. Decker testified that as part of the Settlement LaPorte County now has the vitally needed economic development partner in NIPSCO which has committed to support, review and through the Settlement, earmarked $2.5 million for economic development substation needs and another $1 million for necessary distribution upgrades in essential electric infrastructure. He stated that NIPSCO has recognized that LaPorte County needs better, state-of-the-art electric infrastructure located in and supporting the Kingsbury Industrial Park to assist in bringing world-class industrial and commercial development to the park.

Mr. Decker testified the agreed-to substation and distribution upgrades to the aging electric utility infrastructure in Kingsbury Industrial Park is the type of economic development contemplated by Ind. Code § 8-1-39. He further testified that NIPSCO has long talked about wanting to be a full partner in economic development efforts. He stated LaPorte County suffers from unemployment rates that are higher than both the state and national averages. He noted that supporting and inducing a major transloading operation or other large production or warehousing operation is key to LaPorte County's local and state job creation efforts. He observed that having improved and updated electric infrastructure capable of supporting major production and distribution facilities is vital. He shared that this potential development could mean over a thousand good paying jobs for the LaPorte County economy. Mr. Decker testified LaPorte County needs and deserves this kind of economic development assistance from NIPSCO which would come at a critical time in its job creation efforts.

E. LaPorte Witness Schellinger. James Schellinger, President of the Indiana Economic Development Commission, on behalf of LaPorte, provided testimony to show his support for and commend the parties for recognizing the inherent value in promoting ongoing Indiana economic development that is needed to help encourage growth of existing businesses and to help entice and locate new business and industry within the State of Indiana. He testified there that have already been significant efforts put in place at the Kingsbury Industrial park to facilitate large scale development. He stated this is an excellent example of public-private initiatives that are key to expanding and enhancing economic development efforts in the State. He noted that the local governmental bodies and private investors have already spent millions of dollars on the installation of infrastructure. He also confirmed the Kingsbury Industrial Park has been designated a "Select Site" by the CSX Railroad – one of the only industrial parks in Indiana that has two Class I railroads that run parallel to and into the park.

Mr. Schellinger stated that the proximity of the Kingsbury Industrial Park to the Chicago and Northwest Indiana areas makes this an ideal location that is ripe for significant expansion and development. He stated that having the committed support from NIPSCO through the Settlement only further enhances the prospects of the success for LaPorte County and the State of Indiana to land not one, but several new large production, distribution and warehousing facilities at that location. Therefore, Mr. Schellinger applauded the parties for incorporating this particular piece into the Settlement and encourages this type of cooperative effort to continue so that this results in a win-win situation for LaPorte County, NIPSCO and its customers, as well as the State of Indiana.

F. LaPorte Witness Johnson. Jeffrey L. Johnson, President of the Kingsbury Utility Corporation, on behalf of LaPorte, testified Kingsbury is a customer of NIPSCO and has extensive facilities in the Kingsbury Industrial Park. Kingsbury Utility also serves customers located in the Park. Mr. Johnson is very familiar with the territory, the customers in that area, and the electric distribution facilities located there. Mr. Johnson noted he also served as a member of the LaPorte County Redevelopment Commission for a period of time and knows personally how hard county officials are working to promote economic development and job creation in LaPorte County.

Mr. Johnson stated that as the owner of the Kingsbury water and sewer utility serving the Kingsbury Industrial Park area he is very familiar with both the area and the electric distribution system serving both its facilities and the shared customers. He testified the Kingsbury area was originally built as a World War II government owned and operated ordnance plant. After the end of the war, the ordnance plant was systematically wound down and turned over to private ownership and ultimately converted to an industrial park. He stated that since the 1950s the area has had some success in attracting small-scale commercial and smaller industrial manufacturing entities that have taken over and reutilized some of the former military buildings, or built their own operations there.

Mr. Johnson stated that a significant economic development push was made in the early 2000s to create a shovel-ready industrial park which is now known as the Kingsbury Industrial Park. He testified a significant effort to jump-starting larger scale development in that area was the commitment of millions of dollars and installation of a significant railroad spur and other infrastructure that has now been constructed in the Kingsbury Industrial Park by CSX and developers who have worked closely with LaPorte County government. However, most of the actual electric utility infrastructure facilities still date back several years, some as far back as the 1950s. He indicated that certain portions of the electric distribution system are beginning to show their age and are in need of update. Mr. Johnson testified personally of various outages in the park in 2013 and 2014 that might have been averted were there updated infrastructure present. He stated that any loss of power provides a loss of revenue to energy intensive industries in the Park and so any improved infrastructure that improves reliability and lessens unplanned interruptions in power would be welcome.

Mr. Johnson supports the need for the $2.5 million substation upgrade and an additional $1 million for distribution economic development upgrades NIPSCO has committed to provide. He testified that as a local business owner and the owner of the Kingsbury Utility Corporation he has agreed to continue to work closely with NIPSCO, the County and state officials to promote development in the Kingsbury Industrial Park. He testified the Settlement provides a solid commitment to ensure sufficient and necessary electric infrastructure is available and Kingsbury is best positioned to meet economic development needs. He stated that last summer Kingsbury had a large international tire company that narrowed its focus for locating a new plant to 10 sites from the forty-five sites that were initially considered. Kingsbury Industrial Park was on the short list. He stated there have been similar requests from large food processing entities who want to locate in Kingsbury Industrial Park primarily because of the newly installed rail spur and the access to the CSX mainline. He stated that although they have made a very good bid for all of those new large businesses, if they had the Settlement to put forward he truly believes that would have significantly helped to tip the scales in their favor over competing sites in other states. He stated they must be ready and in a position to not only entice these new large customers into LaPorte County but be ready to provide the necessary underlying utility infrastructure needs as well. He stated that LaPorte County, the developers, Kingsbury Utility Corporation, NIPSCO and the state have already committed resources to promote the Kingsbury Industrial park economic development efforts and the Settlement will only help to solidify all of those efforts.

Mr. Johnson believes the Settlement and the funding commitments provided by NIPSCO for economic development efforts are in the public interest. He testified he is actively involved in meeting not only with existing business owners, but also meeting with and promoting new development in LaPorte County. He noted that improving the electric infrastructure in and around the Kingsbury Industrial Park has always been a key concern and with this immediate commitment, he is confident that they will now be able to show business owners that providing needed and reliable electric facilities is top priority and will ensure they stay competitive. This commitment by NIPSCO will enhance the ability to bring in new business and industry to the area which will benefit all customers.

G. Municipal Utilities Witness Sommer. Theodore Sommer, Partner with the firm of London Witte Group, LLC, on behalf of Municipal Utilities, offered testimony in support of the Settlement, particularly as it relates to NIPSCO's proposed mass LED TDSIC retrofit program. He testified LED lighting will enhance safety, promote economic development and urban renewal, and provide better illumination. He stated the members of IMUG will implement the change out of their municipally owned streetlights to LED in conjunction with NIPSCO's change out to take full advantage of the economy of scale savings. He stated the most effective way to make the transition is through a competitive RFP process for the purchase and for contractors to make the change outs. He noted that fixtures would be bulk purchased from the best performing vendor(s). To facilitate that possibility, NIPSCO will collaborate with interested municipalities on the selection of LED procurement and installation contractors and that to the extent municipalities and NIPSCO find it beneficial, they may combine or submit orders concurrently for mutual cost savings.

Mr. Sommer testified there are 11,200 streetlights in the cities and town represented by IMUG, two-thirds of which are owned by NIPSCO. He stated that based on his review the current NIPSCO area streetlights provide relatively poor illumination and he considers them obsolete when compared to current LED lighting that are more energy efficient, provide lower O&M costs and provide much better illumination. He noted that streetlights owned by NIPSCO were largely installed in the mid-1980s and are now old, largely depreciated, obsolete, and very inefficient. He stated that replacing them a few at a time with new LED lights forgoes the material savings to be achieved from the economy of scale mass purchase and mass installation of thousands annually.

Mr. Sommer testified that in its case-in-chief NIPSCO proposed to change out all of its streetlights to LED lighting through its TDSIC filings prior to its next base rate case. He commended NIPSCO for its TDSIC inclusion of its LED mass retrofit program but noted what remains is the design and implementation of low cost mass LED retrofit rates. He stated that NIPSCO's proposed Rate 750 LED rates proposed in NIPSCO's pending rate case (Cause No. 44688) should not apply to a mass retrofit of streetlights because those rates would fail to reflect the lower LED purchase and installation costs to be obtained from highly competitive RFPs for thousands of lights. He testified the LED mass retrofit rates that will result from approval of the settlement in NIPSCO's pending rate case (Cause No. 44688) and approval of the Settlement in this Cause will reflect these savings and more accurately price LED streetlights capital and installation costs.

Mr. Sommer stated that IMUG supported NIPSCO's 2014-2020 Electric TDSIC Plan and the mass LED retrofit approved in Cause No. 44370 but that for reasons other than streetlights, that order was remanded after appeal and ultimately the available revenue levels were reduced. He noted that in NIPSCO's pending rate case (Cause No. 44688), IMUG joined the other settling parties in a settlement that provides that the rates proposed in this proceeding and finalized in the initial TDSIC tracker proceeding would apply to any mass LED retrofit program that may be approved by the Commission in this proceeding. He noted that NIPSCO Exhibit 19-S-D sets out LED mass retrofit noncapital cost components. Appendix 6 to NIPSCO's 7-Year Plan lists the number of LED retrofits to be done annually from 2017-2022 and the order of the municipalities in which the LED retrofits will occur.

Mr. Sommer testified the Settlement sets forth the framework for finalizing the LED mass retrofit rates capital costs after contractor responses to RFPs for mass LED purchase and installation contracts are negotiated. He stated that unlike other TDSIC capital additions, IMUG agreed in the Settlement that 50% of the installed costs would be reflected in the LED mass retrofit rates and 50% in the TDSIC tracker. Mr. Sommer stated that at last with the approval of the settlement in NIPSCO's pending rate case (Cause No. 44688) and the Settlement in this proceeding, NIPSCO's mass retrofit LED program will be implemented and rates that reflect the mass purchase and installation savings will soon be finalized in a compliance filing once the results of the RFPs are known and the substantial utility, customer and societal benefits LED streetlights offer will begin to be realized.

Mr. Sommer testified the number of annual LED streetlights retrofits NIPSCO proposes offer the economy of scale procurement and installation savings opportunities noting that if bid as a multi-year program, it may yield even more savings. He stated it is critical that mass LED retrofits be based on broad competitive procurement and installation RFPs. He noted mass LED retrofits based on competitive RFPs have been done in other municipalities and have resulted in material savings in both the purchase price and installation cost. Mr. Sommer testified prudent planning and management would harvest this savings opportunity and reasonable ratemaking would reflect the savings in customer rates. He stated citizens within NIPSCO's service territory deserve the visible benefits LEDs create and the savings a well-designed and deployed LED retrofit program offers.

Mr. Sommer pointed out that to their credit, NIPSCO is the first investor owned utility in Indiana to roll out an LED streetlights retrofit program within the ratemaking process and we need to get it right as the first approved proposal often creates a regulatory pattern for others to follow. He noted that it would be unreasonable for the citizens of Indiana to be charged LED streetlights replacement rates that do not reflect the savings that will be achieved from competitive bidding for mass LED streetlights retrofits and lower operating costs as those savings are important to Indiana municipalities. The Settlement sets forth such a framework.

Mr. Sommer set out the benefits of LED streetlights as enhanced public safety, enhanced economic development, streetlights energy reductions of up to 60%, lower maintenance costs, extended useful life, greater lighting reliability, better visibility and aesthetic value, light that is focused rather than dissipated, urban renewal, and, while streetlightsing always enhances safety, it is particularly so in northern Indiana where lake effect winter snows are often sudden and heavy. Mr. Sommer also set out the benefits of LED streetlights to NIPSCO as they use less electricity and put less load on NIPSCO distribution system assets, extends their life and enhances distribution system reliability. He noted that asset reliability is also enhanced by the fact that LEDs have much longer lives and operate at lower temperatures, reducing needed repairs and lamp washing. He also noted that when an HPS light fails it goes dark but because LED streetlights are actually a large grouping of small LED lights, individual cells can fail and the streetlights will still yield needed levels of white light. He stated that the saved energy use of LEDs also results in lower air emissions. Another benefit is they weigh less and are easier to install making work easier and safer for NIPSCO's workers. Mr. Sommer concluded LED streetlights improve visibility, aesthetics, safety and in turn enhance customer satisfaction. Mr. Sommer testified the risk of failure to deploy a well-designed program to retrofit streetlights is lack of enhancement of public safety and suppression of night time social and business activity. He stated that failed and inadequate streetlightsing decrease public safety and diminish economic well-being. To drive his point home, he said accidental injury, death or victimization by violent crime are the consequences of children walking home in the dark or playing in poorly lit areas, or of adults walking or driving in poorly lit area. The consequences of poor lighting in commercial areas are decreased or no commercial business at night and an attendant loss of economic stability or growth. Mr. Sommer believes that reasonably improving its lighting system to provide this enhanced safety and crime retarding benefits also provides a benefit to NIPSCO both as a responsible corporate citizen and in enhanced customer satisfaction.

Mr. Sommer testified the expenditures related to the mass retrofit LED streetlights program satisfy the TDSIC standard criteria as follows:

- Modernization: NIPSCO streetlights are primarily high pressure sodium installed in the mid-1980s that are now at the end of their life, emit decreased illumination, require higher maintenance and use approximately 50% more energy than comparable LED streetlights. Modernizing all of NIPSCO's streetlights in a single LED program effort will result in lower O&M costs, lower energy usage and very large capital savings from the economy of scale purchase of replacement LED lights and minimize contract installation costs.

- Safety: The American Association of state highway and transportation officials have stated "Improved safety is the primary goal of public lighting." There is substantial documentation of improved public safety as a result of the improved visibility created by LEDs. Crime rates go down, vehicular accidents go down, and pedestrian safety is increased. Streetlightsing is typically the most costly electricity expenditures for municipalities. To the same extent that LEDs yield savings, municipalities can use those savings for other important activities such as increased fire and police protection. LEDs also enhance utility employee safety by providing them better visibility at night and LED lights are substantially lower and easier to manage in inventory, on trucks, and in elevated booms, making injury to utility workers and contractors less likely. LEDs operate at low temperature and therefore do not become as dirty making it easier to clean them and require less frequent cleaning. Reducing the time utility workers are in roadways cleaning streetlights enhances utility worker safety. LEDs last about four times longer thus reducing the need for utility workers to replace them, again improving utility worker safety as they perform their tasks on streetlights in roadways.

- Reliability: LEDs enhance reliability in multiple ways, including the best performing LEDs come with a ten year replacement warranty as compared to four or five years (and can last for as long as 20 years or more), LEDs use 50% to 60% less electricity resulting in less load on the electric circuits which increases the life expectancy of distribution equipment, in some high crime areas streetlights are shot out and if not all individual LED lights are damaged the light can continue to illuminate enhancing the reliability of streetlights, not to mention public safety.

- Economic Development: LEDs enhance economic development. Dim, orange tinted, poorly illuminated lighting does not promote a sense of safety and the level of visibility that LED lights provide. Lighting makes people feel and be safe. Quality lighting creates and encourages a pedestrian friendly environment beneficial to neighborhood business districts and commercial areas. Downtown urban areas benefit from improved nighttime lighting by attracting more people and thus promoting economic growth. LEDs promote economic growth through assisting in the revitalization and urban renewal of old or blighted areas. Bringing light to dark or dim areas gives community members a better opportunity to interact in nighttime social activities and a better appreciation for their neighborhoods and increased price in community. It enhances positive interest in neighborhoods by improving safety and encourages people to do even more in improving where and how they live. When neighborhoods improve, the value of the property in those areas improve, property owner's benefit and property tax revenues increase.

Mr. Sommer recommended the Commission approve NIPSCO's TDSIC proposal to mass retrofit all its streetlights in its electric service area to LED within this 7-year plan as agreed to in the Settlement.

H. Municipal Utilities Witness Kramer. Robert Kramer, Professor of Physics, NiSource Charitable Foundation Professor of Energy and the Environment, Director of the Energy Efficiency and Reliability Center, on behalf of Municipal Utilities, offered testimony in support of the Settlement, particularly as it relates to NIPSCO's proposed mass LED TDSIC retrofit program. He testified that he supports the replacement of all NIPSCO's old technology streetlights with new LED streetlights. He described the older technologies of streetlightsing and why newer technology is better. He stated that the technological advances of the LED streetlights provide substantial advantages and noted that LED technology is nationally the most widely implemented replacement for HPS luminaires. He explained that high quality modern LED based luminaires provide up to a 60%+ decrease in energy usage, long life estimated at 100,000 hours or more, competitive price, excellent light color characteristics, instant starting, full dimming capability, highly directional light, resistance to vibration and relatively small size and light weight luminaires that facilitate storage and installation. He pointed out the O&M cost savings from LED streetlights. Dr. Kramer noted that this modern technology is being implemented in numerous locations and metropolitan areas globally including major replacement programs involving retrofits of 141,089 streetlights in Los Angeles and 300,000 in New York. He detailed the savings to be achieved by competitive requests for proposals ("RFPs") for the purchase and mass contractor retrofit installation of LED retrofits. Dr. Kramer stated that in his opinion LEDs are the best choice for large scale light replacements for many beneficial reasons. Notably, Dr. Kramer stated the benefits as:

- Improved public safety because they provide better-quality, white light, it improves visual clarity.
- Maintenance and installation benefits because LED lights have a long useful life or 100,000+ hours. This extended life will substantially reduce the frequency of lighting maintenance and consequently materially reduce maintenance costs and the exposure of employees to associated maintenance hazards. LEDs operate at much lower temperature than current technology lights, which means dirt does not get baked on as it does with lights operating at a higher temperature. Therefore, less frequent cleaning is required. LED streetlights luminaires also frequently come with ten-year replacement warranties, thereby drastically reducing or eliminating the equipment financial risk due to failures during that time period. Finally, regarding installation costs, LEDs are often shipped directly to the mass installation contractor eliminating initial storage and handling costs.
- Revitalization of blighted or deteriorating neighborhoods, including improved public safety which indicates a decrease in crime, for example in L.A. a decrease in theft from vehicles of 10.67%, a decrease in burglary-robbery-theft of 6.40%, and a decrease in vandalism of 10.90% for a total decrease in these categories of 8.9%.
- Reduced electricity consumption, costs, and environmental emissions
- Promotion of economic development, because exterior lighting has a significant impact on economic development. Lighting can draw people to a downtown area or a shopping area by making the shops and restaurants inviting and safer.

- Improved safety of utility employees
- Reduction of loading on NIPSCO's electric distribution system
- Enhanced reliability of NIPSCO's distribution system that serves areas with streetlightsing.
- Improved quality of life in urban areas.

Dr. Kramer noted that the time is right for mass retrofit of current streetlights with new LED streetlights, and they should not be delayed. He noted that the value of the lost savings, approximately 60% or more reduction in energy use, 50% reduced maintenance costs, and many other safety, economic and social benefits exceeds the value of any remaining future LED improvements. The capital cost savings from competitive RFPs for procurement and installation of mass retrofitting current streetlights with new LED's, combined with the noted O&M savings offers the opportunity for low cost mass retrofit LED streetlights rates. He offered his opinion of the per unit installation costs that are possible.

Dr. Kramer testified a mass LED retrofit program will satisfy the TDSIC criteria by modernizing and making more efficient and reliable the streetlights portion of NIPSCO's distribution system. Decreased system demand, vastly extended streetlights useful lives will increase reliability and improve nighttime safety. LED streetlights will enhance economic development by facilitating increased nighttime business activities and promoting urban renewal and increased property values.

7. Commission Discussion and Findings.

A. Consideration of Settlement. Settlements presented to the Commission are not ordinary contracts between private parties. *United States Gypsum, Inc. v. Indiana Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). Any settlement agreement that is approved by the Commission "loses its status as a strictly private contract and takes on a public interest gloss." *Id.* (quoting *Citizens Action Coalition v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coalition*, 664 N.E.2d at 406. Furthermore, any Commission decision, ruling, or order – including the approval of a settlement – must be supported by specific findings of fact and sufficient evidence. *United States Gypsum*, 735 N.E.2d at 795 (*quoting Citizens Action Coalition v. Public Service Co.*, 582 N.E.2d 330, 331 (Ind. 1991)). Therefore, before this Commission can approve the Settlement, we must determine whether the evidence in this Cause sufficiently supports the conclusion that the Settlement is reasonable, just, and consistent with the purpose of Ind. Code Ch. 8-1-2, and that such Settlement serves the public interest.

At the same time, Indiana law strongly favors settlement as a means of resolving contested proceedings. *See, e.g., Manns v. State Dept. of Highways*, 541 N.E.2d 929, 932 (Ind. 1989); *Klebes v. Forest Lake Corp.*, 607 N.E.2d 978, 982 (Ind. Ct. App. 1993); *Harding v. State*, 603 N.E.2d 176, 179 (Ind. Ct. App. 1992). A settlement agreement "may be adopted as a resolution *on the merits* if [the Commission] makes an independent finding supported by 'substantial evidence on the record as a whole' that the proposal will establish 'just and reasonable' rates." *Mobil Oil Corp. v. FPC*, 417 U.S. 283, 314 (1974) (emphasis in original). *See also, Indianapolis Power & Light Co.*, Cause No. 39938, p. 7 (IURC 8/24/95); *Commission Investigation of Northern Indiana Public Service Co.*, Cause No. 41476, p. 23 (IURC 9/23/02). This policy is consistent with expressions to the same effect by the Indiana Supreme Court. *See, e.g., Mendenhall v. Skinner & Broadbent Co.*, 728 N.E.2d 140, 145 (Ind. 2000) ("The policy of the law generally is to discourage litigation and encourage negotiation and settlement of disputes.") (citation omitted); *In re Assignment of Courtrooms, Judge's Offices and Other Facilities of St. Joseph Superior Court*, 715 N.E.2d 372, 376 (Ind. 1999) ("Without question, state judicial policy strongly favors settlement of disputes over litigation.") (citations omitted). Furthermore, the Commission is mindful regarding a settlement which has been entered into by representatives of all customer classes, including the OUCC (who represents all ratepayers), even though there may be some intervenor or group of intervenors who opposes it. *American Suburban Utils.*, Cause No. 41254, pp. 4-5 (IURC 4/14/99).

The Commission has carefully analyzed the evidence and the proposed Settlement to evaluate whether the proposed outcome is reasonable and in the public interest. Based on that review, we conclude that the Settlement is reasonable and in the public interest and should be approved. The Settlement is attached hereto and incorporated herein by reference.

B. 7-Year Electric Plan. Indiana Code § 8-1-39-10 permits a public utility to petition the Commission for approval of the public utility's seven year plan for eligible transmission, distribution, and storage system improvements.

Ind. Code § 8-1-39-10(b) states that after notice and a hearing, and not more than 210 days after the petition is filed, the commission shall issue an order that includes the following:

(1) A finding of the best estimate of the cost of the eligible improvements included in the plan.

(2) A determination that the public convenience and necessity require or will require the eligible improvements included in the plan.

(3) A determination whether the estimated costs of the eligible improvements included in the plan are justified by incremental benefits attributable to the plan.

Further, "[i]f the commission determines that the public utility's seven (7) year plan is reasonable, the commission shall approve the plan and designate the eligible transmission, distribution, and storage improvements included in the plan as eligible for the TDSIC treatment." *Id.*

Ind. Code § 8-1-39-2 defines "eligible transmission, distribution, and storage system improvements" as new or replacement electric or gas transmission, distribution, or storage utility projects that

(1) a public utility undertakes for purposes of safety, reliability, system

modernization, or economic development, including the extension of gas service to rural areas;

(2) were not included in the public utility's rate base in its most recent general rate case; and

(3) either were:

(A) designated in the public utility's seven (7) year plan and approved by the commission under section 10 of this chapter as eligible for TDSIC treatment; or

(B) approved as a targeted economic development project under section 11 of this chapter.

In its Post-Hearing Brief, the CAC raises three issues with the Settlement, which we restate as follows: CAC contends that Ind. Code ch. 8-1-39 does not allow for a utility to seek simultaneous relief under Chapter 39 and a base rate proceeding; CAC contends that the Settlement ignored consideration of measures such as demand-side management and distributed generation (described as "non-wire alternatives"), and as such, failed to demonstrate that the relief requested is reasonable and necessary, or that the Plan costs are justified by the incremental benefits of the Plan. We address the CAC positions in the discussion below.

1. Content of the Plan and Project Eligibility

The 7-Year Electric Plan presented in this proceeding [Petitioner's Exhibit No. 2, Attachment 2-A (Confidential)) inclusive of portions of Appendices 1 through 5 thereto, and detailed in the exhibits and work papers of Russell L. Atkins and Timothy R. Caister] includes a detailed and defined roadmap for how NIPSCO intends to achieve its objectives of maintaining safe, reliable service for NIPSCO customers. The evidence of record establishes that NIPSCO reviewed all of its transmission and distribution assets to develop its 7-Year Electric Plan. NIPSCO's 7-Year Electric Plan provides a detailed overview of what types of projects need to be undertaken, and why these types of projects are necessary. The record supports that each of those projects are to be undertaken for purposes of safety, reliability and/or system modernization. We find that the projects identified in the 7-Year Electric Plan are "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code § 8-1-39-2. Based upon the evidence, we also find that NIPSCO has provided individual improvement level detail sufficient to reasonably identify what projects will be completed and when. *NIPSCO Indus. Grp. v. Northern Ind. Pub. Serv. Co.,* 31 N.E.3d 8, 8 (Ind. Ct. App. 2015), *see also Indiana Michigan Power Company,* Cause No. 44542, 2015 WL 2250624, at *11 (IURC 5/8/15). Based on the evidence of record, we find that NIPSCO has presented a plan that meets the requirements of a 7-Year Plan under Ind. Code §8-1-39-10(a).

2. Best Estimate of Cost of Eligible Improvements.

Ind. Code § 8-1-39-10(b)(1) requires that an order approving a utility's 7-Year Plan include a finding of the best estimate of the cost of the eligible improvements included in the plan. While we have encouraged utilities to improve the level of accuracy and completeness of their cost estimates prior to seeking Commission pre-approval for a project, we have also recognized that the circumstances of a project may dictate the appropriate range of accuracy. *See Northern Indiana Public Service Company,* Cause No. 44012 at 18 (IURC 12/28/11). The framework of this proceeding was established by the TDSIC statute that requires a public utility seeking approval to submit a plan for seven years of eligible improvement capital investment. It is reasonable that a 7-Year Plan for any public utility must necessarily include some level of flexibility to address changing circumstances. The Settling Parties have reached agreement on cost recovery caps and specific provisions to afford NIPSCO appropriate flexibility to address reasonable changes in conditions that may impact the 7-Year Electric Plan.

The uncontested evidence of record supports the conclusion that NIPSCO's estimating techniques and cost estimates summarized in Petitioner's Exhibit No. 2, Attachment 2-A are reasonable and appropriate and represent the best estimates of the costs of the 7-Year Electric Plan -- a conclusion that is also supported by the Settlement. Mr. Atkins provided extensive testimony that explains the process for developing the cost estimates for each category of projects. We accordingly find that NIPSCO has supported the 7-Year Electric Plan with appropriate and reasonable cost estimates that constitute best estimates of the costs associated with the Plan.

3. Public Convenience and Necessity.

Ind. Code § 8-1-39-2 defines eligible transmission, distribution, and storage system improvements as projects undertaken for purposes of safety, reliability, system modernization, or economic development. Mr. Caister testified that in order to continue serving its customers safely and reliably, the assets in the 7-Year Electric Plan need to be replaced. NIPSCO has a statutory obligation to provide adequate retail service, pursuant to Ind. Code § 8-1-2.3-4(a), in its assigned electric service territory.

In its Post-Hearing Brief, CAC first argued that approval of the Plan in conjunction with a base rate proceeding is not in the public interest and should not be allowed. CAC cited to Ind. Code § 8-1-39-9 in support of its position. However, NIPSCO has not requested relief under Section 9, which applies to TDSIC tracker proceedings. Instead, this Cause was initiated under Section 10, which applies to the initial approval of a TDSIC plan. Nothing in Section 10 limits a utility from seeking base rate relief and approval of a seven-year plan to improve transmission and distribution plant.

CAC also argued that by failing to adequately discuss demand-side management ("DSM") and distributed generation in its 7-Year Plan, NIPSCO cannot demonstrate that public convenience and necessity require approval of the Plan. We disagree. CAC elected not to provide any evidence to support its assertion that investment in non-wire alternatives would reduce the need to replace aging transmission and distribution infrastructure.

We find that NIPSCO has sufficiently supported that the investments described in its 7-Year Electric Plan are reasonably necessary for it to continue to provide adequate retail service to its assigned customers. Therefore, based upon the evidence presented in this proceeding, we find that the public convenience and necessity require or will require the eligible improvements included in the 7-Year Electric Plan.

4. Incremental Benefits.

The evidence of record shows that NIPSCO has a large number of aging assets on its electric transmission and distribution system. The assets appear to have aged naturally as a function of NIPSCO's service territory development over time and the natural life of the assets. The evidence supports NIPSCO's position that these assets need to be replaced. NIPSCO's 7-Year Electric Plan puts forth a plan to address these replacements. NIPSCO engaged a third party to conduct a quantitative risk assessment of these assets. NIPSCO presented this risk analysis which took into account both likelihood of failure and consequence of failure.

In its Post-Hearing Brief, CAC argued that by failing to adequately discuss non-wire alternatives in its 7-Year Plan, NIPSCO cannot demonstrate the Plan costs are justified by the incremental benefits of its Plan. As discussed above, CAC presented no evidence that non-wire alternatives have any impact on the need to replace aging transmission and distribution resources. Here, NIPSCO presented evidence that the incremental benefits of replacing the aging transmission and distribution infrastructure using a planned approach are justified by the costs of the Plan. No evidence was presented that the impact of non-wire alternatives, if any, would change the cost justification of the Plan.

In summary, there is sufficient evidence replacing aging infrastructure will reduce the likelihood of potential system outages. We find that NIPSCO has provided sufficient evidence that the estimated costs of the eligible improvements included in the 7-Year Electric Plan are justified by the reasonably expected incremental benefits attributable to the Plan.

5. Approval of 7-Year Electric Plan.

As noted above, if the Commission finds a seven-year plan to be reasonable, the plan shall be approved and the projects shall be designated as eligible for TDSIC treatment.

Based upon our review of the evidence of record, and the foregoing considerations of each component of Ind. Code § 8-1-39-10, we find that NIPSCO's 7-Year Electric Plan is reasonable. Specifically, the 7-Year Electric Plan submitted in this proceeding contains individual improvement level detail sufficient to allow the Commission to reasonably identify what projects will be completed and when. *NIPSCO Indus. Grp. v. Northern Ind. Pub. Serv. Co.,* 31 N.E.3d 8, 8 (Ind. Ct. App. 2015), *see also Indiana Michigan Power Company,* Cause No. 44542, 2015 WL 2250624, at *11 (IURC 5/8/15). Moreover, the Settlement provides for the continued provision of the same detailed information about projects in the 7-Year Electric Plan as part of Petitioner's semi-annual filings while maintaining appropriate levels of flexibility which is both reasonable and consistent with the public interest. We also find the inclusion of the mass retrofit LED Streetlight project into the 7-Year Electric Plan to be appropriate in light of the evidentiary record.

Indiana Code § 8-1-39-9(d) states that "[a] public utility that implements a TDSIC under this chapter shall, before the expiration of the public utility's approved seven (7) year plan, petition the commission for review and approval of the public utility's basic rates and charges with respect to the same type of utility service." Therefore, NIPSCO shall petition the Commission for review and approval of NIPSCO's basic retail electric rates and charges by December 31, 2022, which is the last day of NIPSCO's 7-Year Plan.

C. Settlement Provisions. The following is a description of some of the significant provisions of the Settlement supporting the determination that it is reasonable and in the public interest:

1. 7-Year Electric Plan Approval and Deferral Authority

The Settlement calls for the approval of the $1.33 billion 7-Year Electric Plan subject to a negotiated limit of $1.25 billion of direct capital, indirect capital, and AFUDC eligible for TDSIC ratemaking treatment, inclusive of eligible costs incurred from January 1, 2016.

2. Capital Cost Reduction and Cost Recovery Cap

Under the Settlement the entire 7-Year Electric Plan as filed would be approved, with NIPSCO having the flexibility to determine from which projects the negotiated $80 million reduction in cost recovery would be accomplished. NIPSCO would be subject to annual cost recovery caps, subject to the ability to adjust the cap in subsequent years by as much as 5% in a rolling historical three-year period, as follows:

Year	Annual Cost Recovery Cap	Year	Annual Cost Recovery Cap
2016	$135,767,602	2020	$209,560,172
2017	$112,159,247	2021	$213,831,907
2018	$160,259,646	2022	$211,261,638
2019	$209,113,823		

The Settlement provides that NIPSCO will maintain a ratio of 61% distribution projects to 39% transmission projects +/- 1% in the 7-Year Electric Plan and will provide cost estimates detailing this ratio in each update to the Plan.

3. Flexibility within the 7-Year Electric Plan

The Settling Parties recognized that circumstances including system changes, reliability issues, or reasonable and prudent cost changes may dictate that the projects undertaken within the 7-Year Electric Plan be subject to change or re-prioritization, and the Settlement provides that the dollars associated with a specific project can be moved between Plan years, in whole or in part, in recognition of such changes. The Settlement also provides a structure for updating the 7-Year Electric Plan in NIPSCO's semi-annual filings, and includes specific thresholds of materiality that trigger required levels of project detail and/or testimonial support to be provided. The Settling Parties retain the right to challenge any costs that exceed approved estimates in accordance with Ind. Code § 8-1-39-9(f) and to take any position with respect to any new project proposed for inclusion in the 7-Year Electric Plan, but recovery of a maximum of 80% of incurred costs associated with the $1.25 billion in capital expenditures through the TDSIC Rider, and deferral of 20% of such costs for recovery in a future base rate case are not subject to adjustment under the Settlement.

4. TDSIC Tracker Filings

The Settlement addresses the cadence for future TDSIC tracker proceedings under Ind. Code §8-1-39-9. The Settling Parties agreed that the first tracker under the 7-Year Electric Plan would occur on or about July 1, 2016 and would establish factors for the first portion of 2016 that would be implemented with the first billing cycle starting February 1, 2017[6]. The second such tracker filing would be made on or about July 1, 2017, with rates to be effective with the first billing cycle of October 2017, and subsequent tracker filings would occur semi-annually each February and August thereafter. With the exception of the first tracker filing, these proceedings would be undertaken consistent with the statutory 90-day cycle contemplated by Ind. Code § 8-1-39-12(a).

5. TDSIC Tracker Ratemaking

The Settlement addresses and clarifies a range of ratemaking issues relevant to the semi-annual TDSIC tracker filings. These include confirmation of NIPSCO's authority to (i) apply CWIP ratemaking treatment, (ii) continue the statutory 80%/20% recovery and deferral of approved TDSIC costs through its current Rider 688 or its successor, (iii) defer ongoing carrying charges associated with TDSIC projects as a regulatory asset based on NIPSCO's weighted cost of capital, until the deferred TDSIC Costs are included for recovery in rates, and (iv) adjust NIPSCO's authorized net operating income to reflect TDSIC earnings.

The Settlement also addresses several issues that overlap NIPSCO's pending rate case in Cause No. 44688 and the application to NIPSCO's semi-annual TDSIC tracker proceedings. Specifically, the Settlement proposes the following inputs be incorporated into such tracker proceedings:

a. Capital Structure – Calculation of weighted average cost of capital reflective of the components included in the capital structure approved in Cause No. 44688 (Settlement Term 7(e));

b. Return on Equity – Return on equity in TDSIC tracker proceedings to be 9.975% (Settlement Term 7(g)); and

c. Allocation Factors – The allocation factors to be used in NIPSCO TDSIC tracker filings will be those from Cause No. 44688 (Settlement Terms 7(i) and 8(h)).[7]

Under the Settlement, at the time of any subsequent base rate case filed by NIPSCO, TDSIC improvements in-service by the rate base cut-off date will (subject to a normal prudence review in the TDISC Rider proceedings) be included in rate base and NIPSCO's new base rates along with the 20% of the T&D improvements associated with the 7-Year Electric Plan that have

[6] On June 30, 2016, NIPSCO filed a Petition docketed as Cause No. 44733 TDSIC 1.
[7] As addressed below, our approval of this Settlement should not be construed as prejudging any issue pending in Cause No. 44688.

been deferred with carrying costs in this proceeding. The TDSIC Rider then will be subject to the return on equity and allocation factors ultimately approved by the Commission in the subsequent base rate case. The Settlement provides that if a final Order is approved in a base rate case during the term of the 7-Year Electric Plan, the recovery caps incorporated into the Settlement will remain in effect for 2016 – 2022 unless a new 7-Year Plan is approved by the Commission.

The Settlement also contains ratemaking provisions for the implementation of a mass retrofit LED Streetlight project for NIPSCO-owned streetlights. The project would be undertaken based on the results of an RFP to be conducted seeking competitive bids for the procurement and for the installation of LED streetlight fixtures consistent with the 7-Year Electric Plan. Once qualified bidders for LED supply and installation have been selected and an updated, estimated cost of the mass retrofit LED Streetlight project obtained, 50% of the estimated per lamp revenue requirement associated with the installed cost would be included in a streetlight lamp rate applicable to each fixture as part of NIPSCO's tariff rate. The remaining 50% of the estimated revenue requirement and all variances associated with the estimated revenue requirement for all installed fixtures would be recoverable as TDSIC through NIPSCO's TDSIC Rider.

6. Economic Development

The Settlement provides for inclusion of up to $3.5 million for an Economic Development project for the LaPorte County Kingsbury Industrial Park ("Kingsbury Project") including a $2.5 million project for substation upgrades proposed in the Rate Case Settlement and up to $1.0 million for other distribution infrastructure upgrades. The Settlement calls for details of any capital expenditures for the Kingsbury Project to be presented by NIPSCO and LaPorte County in a tracker filing by NIPSCO subject to the right of other Parties to timely take any position on the expenditures in future proceedings. Any approved Economic Development project during the term of the T&D Plan, including the Kingsbury Project, will not be included in the $1.25 billion capital cost recovery cap nor in the annual recovery caps agreed to in the Settlement.

In order to keep the Commission apprised of the progress on the Kingsbury Project, NIPSCO shall provide notice, under this Cause, within 15 days of the date that upgrades for the Kingsbury Project begin.

7. Mass LED Streetlight Retrofit Plan and Rates

The Settlement establishes a reasonable framework for replacement of NIPSCO's current streetlights with new energy efficient and better illuminating LED technology lights that offer a host of public and operational benefits previously described. This framework includes a process for competitive RFPs for the mass procurement and installation of new LEDs. The evidence shows that material capital cost savings can be achieved by leveraging economies of scale through such competitive bidding. Reflecting the capital costs from that process to produce mass LED retrofit rates in the first TDSIC tracking filing is a reasonable means to move forward with this beneficial lighting distribution system program. Moreover, the Settlement creates an opportunity for municipalities and NIPSCO to work together in the future where appropriate to explore the potential for synergies in the cooperative procurement and installation of municipally owned and NIPSCO-owned LED replacement lights.

D. Process to Update the 7-Year Electric Plan. The Settlement in this proceeding identifies the timing and content of updates to the 7-Year Electric Plan to be presented to the Commission in NIPSCO's semi-annual tracker proceedings. Specifically, in each Fall tracker filing, NIPSCO will provide a detailed list of projects for the upcoming year along with best estimate of project costs and will identify which, if any, of the approved projects will be in whole or in part rescheduled to a Plan year and any associated adjustment to corresponding Plan year caps. In each Spring tracker filing, NIPSCO will provide the actual costs of the projects completed in the prior year and updated projected costs of the projects in the following years. For projects with actual or projected costs higher than the costs previously approved, NIPSCO will provide justification in the form of written variance explanations. Projects with cost variances greater than $30,000 or 15%, whichever is greater, will be supported by a project change request (PCR) form. Projects with cost variances greater than $100,000 or 20%, whichever is greater, will also be supported by written testimony. Parties will retain the ability to challenge any costs that exceed the approved estimates pursuant to Ind. Code § 8-1-39-9(f).

NIPSCO proposed to establish a subdocket for consideration of any major modification to the 7-Year Plan to permit more time for consideration and detailed the steps taken to meet with stakeholders in advance of this filing.

We find that the process for updating the 7-Year Electric Plan in subsequent TDSIC tracker filings is appropriate and should be accepted. We encourage NIPSCO to continue the process of holding stakeholder meetings in advance of each filing in an effort to smooth the expedited 90-day statutory timeline for such filings and to narrow the scope of any contested issues. We note that the resolution of issues in this proceeding will also enhance both of those goals.

E. Conclusion. The Commission concludes that the proposed Settlement is reasonable, in the public interest, and should be approved. As discussed above, the 7-Year Electric Plan is supported not only in the Settlement of the Settling Parties, but also by a substantial and uncontested evidentiary record. We note that the Settlement resolves a number of previously contested issues in a manner consistent with the TDSIC statute, the opinion of the Indiana Court of Appeals and previous orders of the Commission. In so doing, the Settlement provides clarity and predictability in a manner consistent with the public interest and administrative efficiency.

The Settlement provides both the parties to this proceeding and the Commission with a clearly defined structure for the consideration of TDSIC tracker proceedings based on the 7-Year Electric Plan, including agreements on ratemaking and the timing and frequency for those filings. It is evident from the terms of the Settlement that there were compromises undertaken by the Settling Parties as to cost recovery caps, TDSIC tracker factor implementation, and the provision of flexibility in the implementation of the projects included in the 7-Year Electric Plan. We find that the compromises embodied in the Settlement are consistent with the applicable statutory provisions and are reasonable and in the public interest.

We note that several issues resolved in the Settlement refer to issues pending in Cause No. 44688 based on the overlap between the two proceedings. Without compromising our consideration of the evidence in that proceeding, the Commission recognizes that TDSIC tracker filings must by statute incorporate inputs determined in base rate proceedings and that the consistent resolution of issues across cases is advantageous from the perspective of the utility, its customers, and the Commission. To the extent that terms of this Settlement refer to issues currently pending in Cause No. 44688, the terms approved by the Commission in Cause No. 44688 shall apply to the TDSIC tracker proceedings filed in accordance with the 7-Year Electric Plan.

The Settling Parties agree that the Settlement should not be used as precedent in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce its terms. Consequently, with regard to future citation of the Settlement Agreement, we find our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, 1997 Ind. PUC LEXIS 459 at *19-22 (IURC March 19, 1997).

F. Confidentiality. Petitioner filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information on December 31, 2015 supported by affidavit showing documents to be submitted to the Commission were trade secret information within the scope of Ind. Code §§ 5-14-3-4(a)(4) and (9) and Ind. Code § 24-2-3-2. The Presiding Officers issued a Docket Entry on January 14, 2016 finding such information to be preliminarily confidential, after which such information was submitted under seal. On February 1, 2016, Petitioner filed a Second Motion for Protection and Nondisclosure of Confidential and Proprietary Information, and a Docket Entry was issued on February 9, 2016 finding such information to be preliminarily confidential, after which such information was submitted under seal. We find all such information is confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION THAT:

1. The attached Settlement filed in this Cause on March 24, 2016, is approved as set forth herein.

2. The projects contained in NIPSCO's 7-Year Electric Plan are "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code § 8-1-39-2.

3. NIPSCO's 7-Year Electric Plan is reasonable and is approved subject to and consistent with the provisions of the Settlement Agreement.

4. Petitioner's proposed process for updating the 7-Year Electric Plan in future TDSIC semi-annual adjustment proceedings is hereby approved.

5. The information submitted under seal in this Cause pursuant to its motions for protective order is deemed confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-

2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

6. This Order shall be effective on and after the date of its approval.

STEPHAN, HUSTON, AND ZIEGNER CONCUR; WEBER NOT PARTICIPATING:

APPROVED: JUL 12 2016

I hereby certify that the above is a true and correct copy of the Order as approved.

Mary M Becerra

Mary M. Becerra
Secretary of the Commission

OFFICIAL EXHIBITS

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF PETITIONER'S 7-YEAR ELECTRIC TDSIC PLAN FOR ELIGIBLE TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS, PURSUANT TO IND. CODE § 8-1-39-10(a), FOR AUTHORITY TO DEFER COSTS FOR FUTURE RECOVERY, AND APPROVING INCLUSION OF NIPSCO'S TDSIC PLAN PROJECTS IN ITS RATE BASE IN ITS NEXT GENERAL RATE PROCEEDING PURSUANT TO IND. CODE § 8-1-2-23.	)	**CAUSE NO. 44733**

IURC JOINT EXHIBIT No. 1
5-4-16 AT
DATE REPORTER

7-YEAR PLAN AND TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENT CHARGE ("TDSIC") SETTLEMENT AGREEMENT

1. Introduction

This Settlement Agreement ("Settlement" or "TDSIC Settlement") is entered into by and between Northern Indiana Public Service Company ("NIPSCO"), Indiana Municipal Utilities Group, the Indiana Office of Utility Consumer Counselor, LaPorte County Board of Commissioners,[1] NIPSCO Industrial Group and United States Steel Corporation[2] (collectively, the "Settling Parties") solely for purposes of compromise and settlement. The Settling Parties agree that this Settlement resolves all disputes, claims and issues arising from the Indiana Utility Regulatory Commission ("Commission") proceeding regarding NIPSCO's TDSIC filing currently pending in Cause No. 44733, as between the Settling Parties.

[1] LaPorte County Board of Commissioners' signature page will be late-filed upon receipt of authorization from the Board following its noticed and scheduled meeting.

[2] United States Steel Corporation's signature page will be late filed upon receipt of authorization from U.S. Steel's executive management.

2. NIPSCO's T&D Plan

The Settling Parties agree that the Commission should approve, as "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code ch. 8-1-39 (the "TDSIC statute"), the projects summarized in NIPSCO's 7-Year Electric TDSIC Plan (Petitioner's Exhibit No. 2, Attachment 2-A (Confidential)) inclusive of portions of Appendices 1 through 5 thereto, and detailed in the exhibits and workpapers of Russell L. Atkins and Timothy R. Caister (the "T&D Plan"). This T&D Plan consists of capital expenditures of up to $1.33 billion, which includes direct capital, indirect capital and allowance for funds used during construction ("AFUDC") over the 7-year period from 2016 through 2022; however, the Settling Parties agree that a maximum of $1.25 billion of direct capital, indirect capital, and AFUDC (collectively "Approved T&D Plan Costs") shall be eligible for the TDSIC ratemaking treatment, as discussed further below.

The Settling Parties agree that NIPSCO has provided detailed project descriptions for the T&D Plan, as well as sufficient cost estimates for the projects, as would support a Commission finding that the T&D Plan is reasonable and in the public interest, that the Approved T&D Plan Costs are justified by the benefits of the plan, and that the estimates summarized on Petitioner's Exhibit No. 2, Attachment 2-A reflect the best estimates of the T&D Plan costs.

3. Deferral Authority

The Settling Parties agree that NIPSCO should be granted authority to defer as a regulatory asset all TDSIC Costs (as defined in Ind. Code § 8-1-39-7) associated with the Approved T&D Plan Costs that are incurred from January 1, 2016 and subsequent to the issuance of an Order in this proceeding until such amounts are recovered through rates.

4. Capital Cost Reductions and Cost Cap

(a) Notwithstanding the T&D Plan described above, in order to compromise and settle this case, NIPSCO has agreed to limit recovery through the TDSIC ratemaking treatment of its capital costs actually expended under its T&D Plan up to $1.25 billion over the 7-year TDSIC period – a reduction in capital costs of $80 million from its as-filed T&D Plan. Pursuant to the TDSIC statute, eighty percent (80%) of TDSIC Costs shall be recovered through its Rider 688 – Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge (the "TDSIC Rider") and twenty percent (20%) shall be authorized to be deferred for subsequent recovery with carrying costs (calculated at NIPSCO's weighted average cost of capital) in a subsequent rate case.

(b) The Settling Parties agree that NIPSCO will remove $80 million of capital expenditures from the TDSIC ratemaking treatment. The Settling Parties request that the Commission approve all projects included in the T&D Plan and that NIPSCO be authorized to use any project included in its $1.33 billion T&D Plan to comprise the up to $1.25 billion in total plan capital expenditures over the 7-year period.

(c) The Settling Parties agree that NIPSCO's annual spend for TDSIC capital costs should be capped at $5 million less than currently projected for Years 1 and 2 (2016 and 2017), $10 million less than currently projected for Year 3 (2018), and $15 million less than currently projected for Years 4, 5, 6 and 7 (2019 through 2022). Subject to adjustments in accordance with Paragraph 5(b) below, accordingly, the annual caps shall be as follows: $135,767,602 for 2016; $112,159,247 for 2017; $160,259,646 for 2018; $209,113,823 for 2019; $209,560,172 for 2020; $213,831,907 for 2021; and $211,261,638 for 2022.

(d) The Settling Parties agree that the Approved T&D Plan Costs eligible for TDSIC ratemaking treatment will not exceed $1.25 billion. NIPSCO shall have the ability to deviate above each annual cost recovery cap by no more than 5% in a rolling historical three-year period. Any amount below the annual cap in a given year may be rolled over as an increase to the cap for the following years within the three year rolling period. Any amount above the annual cap in a given year will operate as an offset to the available cap variance for the following years within the three year rolling period. The following examples document the operation of the 5% deviation within the three-year rolling period:

Example 1 –Illustrative $100 Million Cap per year (Below Annual Cap)

	Year 1	Year 2	Year 3	Year 4
Annual Cap	$100 Million	$100 Million + rollover of $5 Million underspend from Year 1	$100 Million	$100 Million
Actual Expenditure	$95 Million	$100 Million	$100 Million	
Available Cap Variance	$5 Million	5%*(Year 1 Cap +Year 2 Cap) = $10 Million	5%*(Year 1 Cap + Year 2 Cap + Year	5%*(Year 2 Cap + Year 3 Cap +Year 4 Cap) minus

			3 Cap) = $15 Million	overage from years 2 and 3 = $15 Million

Example 1 – Illustrative $100 Million Cap per year (Above Annual Cap)

	Year 1	Year 2	Year 3	Year 4
Annual Cap	$100 Million	$100 Million	$100 Million	$100 Million
Actual Expenditure	$105 Million	$100 Million	$100 Million	
Available Cap Variance	$0	5%*(Year 1 Cap +Year 2 Cap) minus $5 Million overage from Year 1 = $5 Million	5%*(Year 1 Cap + Year 2 Cap + Year 3 Cap) minus overage from Years 1 and 2 = $10 Million	5%*(Year 2 Cap + Year 3 Cap +Year 4 Cap) minus overage from years 2 and 3 = $15 Million

(e) The Settling Parties agree that the overall composition of the projects included in the T&D Plan will be maintained at 61 percent distribution projects and 39 percent transmission projects, plus or minus one percent. With each T&D Plan update, NIPSCO shall provide estimates for planned expenditures through the remaining years of the T&D Plan adhering to this composition requirement.

5. <u>T&D Plan Flexibility</u>

(a) NIPSCO expects to complete substantially all of the projects within the scope of the T&D Plan within the 7-year plan period, and the cost recovery terms are predicated on that understanding. Nothing in this Settlement nor in the T&D Plan obligates NIPSCO to implement the entirety of the T&D Plan over the 7-year period nor to recover the revenue requirement associated with the full $1.25 billion capital cost cap amount over the 7-year period. Rather, NIPSCO shall be authorized to implement components of the T&D Plan in good faith up to the $1.25 billion cap over a 7-year period, as outlined herein, but shall have the flexibility to adjust the T&D Plan as circumstances dictate, consistent with Paragraph 5(b) below. Such circumstances include but are not limited to system changes, reliability issues, or reasonable and prudent cost changes. NIPSCO shall update its T&D Plan at least annually, and shall present such T&D Plan updates to the Commission and Settling Parties, consistent with the TDSIC statute.

(b) Each year in its Fall tracker filing, NIPSCO will provide a detailed list of projects for the upcoming year, with best estimate of project costs, but NIPSCO retains the ability to move projects between years as appropriate. In the event that a given project, in whole or in part, is rescheduled to a different year, the annual cost recovery caps for the affected years will be adjusted by that project's whole or partial approved cost estimate to reflect the change (e.g., if a $10 million project is moved from 2018 to 2019, the annual cap for 2018 will be reduced by $10 million and the annual cap for 2019 will be increased by $10 million). Each year in its Spring tracker filing, NIPSCO will provide the actual costs of the projects completed in the prior year and updated projected costs of the projects in the following years. For projects with actual or projected costs higher than the costs previously approved, NIPSCO will provide justification in the form of written variance explanations. Projects with cost variances greater than $30,000 or 15%, whichever is greater, will be supported by a project change request (PCR) form. Projects with cost variances greater than $100,000 or 20%, whichever is greater, will also be supported by written testimony. The Settling Parties shall retain the ability to challenge any costs that exceed the approved estimates pursuant to Ind. Code § 8-1-39-9(f).

(c) The Settling Parties each reserve the right to take any position with respect to any new project proposed by NIPSCO for inclusion in the T&D Plan in a future TDSIC tracker proceeding, but recovery of a maximum of 80% of incurred costs associated with the $1.25 billion in capital expenditures through the TDSIC Rider, and deferral of 20% of such costs for recovery in a future base rate case shall not be adjusted.

(d) The Settling Parties agree to inclusion of up to $3.5 million for an Economic Development project for the LaPorte County Kingsbury Industrial Park ("Kingsbury Project") including a $2.5 million project for substation upgrades as provided for in the proffered Settlement Agreement submitted in NIPSCO's pending rate case in Cause No. 44688 and up to $1.0 million for other distribution infrastructure upgrades. Any capital expenditures for the Kingsbury Project will be presented in a tracker filing by NIPSCO and LaPorte County, which should provide a sufficient evidentiary showing consistent with and required by Ind. Code Ch. 8-1-39 for the approval of such capital expenditures, and the other Settling Parties each reserve the right to timely take any position on such filing in future proceedings.

Any approved Economic Development project during the term of the T&D Plan, including the Kingsbury Project, will not be included in the $1.25 billion capital cost cap nor in the annual recovery caps agreed to herein.

6. TDSIC Tracker Filings

The Settling Parties agree that the first tracker filing associated with the approved T&D Plan shall occur on or about July 1, 2016 to establish factors for the first portion of 2016 which shall be implemented with the first billing cycle starting February 1, 2017. The second such tracker filing shall be made on or about July 1, 2017, with rates to be effective with the first billing cycle of October 2017 consistent with the statutory 90 day cycle. Subsequent tracker filings would occur semi-annually each February and August thereafter.

7. Other Ratemaking Terms

The Settling Parties agree that NIPSCO will be entitled to the following relief in future tracker proceedings relating to the T&D Plan:

(a) CWIP Ratemaking Treatment. NIPSCO has authority to apply CWIP ratemaking treatment to all eligible transmission, distribution, and storage system improvements associated with the Approved T&D Plan Costs through the proposed TDSIC mechanism.

(b) Recovery Mechanism. NIPSCO will continue to recover 80% of TDSIC Costs associated with Approved T&D Plan Costs through Rider 688 or successor TDSIC Riders as approved by the Commission utilizing the recovery mechanism established in Cause No. 44371.

(c) Carrying Charges. NIPSCO will defer as a regulatory asset ongoing carrying charges based on the weighted cost of capital on all deferred TDSIC Costs associated with Approved T&D Plan Costs until the deferred TDSIC Costs are included for recovery in rates.

(d) Earnings Test. NIPSCO will adjust its authorized net operating income to reflect any approved earnings associated with the TDSIC for purposes of Ind. Code § 8-1-2-42(d)(3) pursuant to Ind. Code § 8-1-39-13(b).

(e) Capital Structure. The capital structure used to calculate the weighted average cost of capital will reflect the components approved in NIPSCO's 2016 base rate case in Cause No. 44688 (i.e. debt, equity, prepaid pension asset, deferred income taxes, etc).

(f) Increase in Total Retail Revenue. NIPSCO will calculate the average aggregate increase in its total retail revenue attributable to the TDSIC to determine whether the TDSIC will result in an average aggregate increase of more than 2% in a twelve month period consistent with the methodology affirmed by the Indiana Court of Appeals in Cause Nos. 44370 and 44371.

(g) Return on Equity. The ROE for the TDSIC Rider will be 9.975%. NIPSCO acknowledges that if the proffered Settlement Agreement submitted in its pending rate case in Cause No. 44688 is approved, the provision in the rate case settlement calling for at least 60% debt financing shall be applicable to the capital projects in the T&D Plan in the aggregate and NIPSCO shall report on compliance status in regard to this debt financing requirement in each financing petition filed with the IURC.

(h) Revenue Requirement Netting. There is no netting in the TDSIC Rider of depreciation or return, meaning, the depreciation expense and/or return associated with retired and replaced equipment will not be netted against the depreciation expense and/or return associated with new equipment in the TDSIC Rider, and base retail rates will not be adjusted for these items.

(i) Allocation Factors. The allocation factors for NIPSCO's TDSIC rider shall be those from NIPSCO's 2016 base rate case in Cause No. 44688. The Settling Parties agree that using such factors complies with the TDSIC statute.

(j) Base Rate Case. No commitments have been made in this Agreement with respect to base rate case timing beyond what is required in the TDSIC Statute. At the time of any subsequent base rate case filed by NIPSCO, the Settling Parties agree that the T&D improvements in-service by the rate base cut-off date will (subject to a normal prudence review in the TDISC Rider proceedings) be included in rate base and NIPSCO's new base rates, and the TDSIC Rider then will be subject to the ROE and allocation factors that are ultimately determined by the Commission in any subsequent retail base rate case. Similarly, the 20% of the T&D improvements associated with the T&D Plan that have been deferred with carrying costs will be included in retail rates and rate base in such subsequent base rate case. If a final Order is approved in a base rate case during the T&D Plan, all recovery caps agreed upon herein will remain in effect for 2016 – 2022 unless NIPSCO files a new TDSIC Plan, which the Commission approves.

(k) LED Streetlights. The Settling Parties agree to NIPSCO's proposed implementation of a TDSIC mass retrofit LED Streetlight project for NIPSCO-owned streetlights subject to the following ratemaking treatment:

(i) NIPSCO shall conduct Requests for Proposals ("RFP") seeking competitive bids for the procurement and for the installation of LED streetlight fixtures to be installed pursuant to this Agreement and NIPSCO's TDSIC Plan.

(ii) The per LED unit capital cost components will be finalized after the contractor responses to the RFPs for mass LED purchase and mass installation contracts are received and the contracts are negotiated and finalized. Upon selection of qualified bidders for LED supply and installation and an updated, estimated cost of the mass retrofit LED Streetlight project, 50% of the estimated revenue requirement (on a per lamp basis) associated with the installed cost shall be included in a streetlight lamp rate applicable to each fixture as part of NIPSCO's tariff rate.

(iii) The remaining 50% of the estimated revenue requirement and including all variances associated with the revenue requirement for all actual installed cost of the mass LED Streetlight project throughout the TDSIC Plan, shall be recoverable as TDSIC Costs as that term is defined in the TDSIC Statute through NIPSCO's TDSIC Rider.

(l) Other. All other issues should be decided as proposed in NIPSCO's case in chief testimony and exhibits.

8. Regulatory and Procedural Terms

(a) The Settling Parties agree that the evidence to be submitted in support of this Settlement, along with the evidence of record, together constitute substantial evidence to support this Settlement and provide a sufficient evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of this Settlement. The Settling Parties shall prepare and file with the Commission as soon as reasonably possible, testimony and proposed order(s) in support of and consistent with this Settlement.

(b) This Settlement is a complete and interrelated package that is intended to resolve all issues between the Settling Parties as to NIPSCO's filing in Cause No. 44733.

(c) The Settling Parties will not appeal or seek rehearing, reconsideration or a stay of a Final Order approving this Settlement in its entirety or without change or condition(s) unacceptable to any adversely affected Party (or related orders to the extent such orders are specifically implementing the provisions of this Settlement), except with the agreement of all Settling Parties on the issues to be subject to rehearing, reconsideration or appeal.

(d) The Settling Parties agree to support in good faith the terms of this Settlement before the Commission and further agree not to take any positions adverse to or inconsistent with the Settlement or any adverse positions against each other with respect to the Settlement before any appellate courts, or on rehearing, reconsideration, remand or subsequent or additional related proceedings before the Commission.

(e) The Settling Parties also agree to support or not oppose this Settlement in the event of any request for a stay by a person not a party to this Settlement or if this Settlement is the subject matter of any other state proceeding.

(f) The Settling Parties shall remain bound by the terms of this Settlement Agreement and shall continue to support or not oppose all the terms of the Settlement on appeal, remand, reconsideration, etc., even if the Commission rejects the Settlement. However, in the event that the Settlement is rejected by the Commission and such rejection is ultimately upheld on rehearing, reconsideration, and/or appeal, at the point when all such proceedings and appeals are complete, this Settlement Agreement shall become void and of no further effect (except for provisions which have already been fully implemented or that are explicitly stated herein to survive termination/voiding).

(g) If the Commission approves the Settlement in its entirety, or approves the Settlement with modifications that are not unacceptable to affected Settling Parties, and such Commission approval is ultimately vacated or reversed on appeal, the Settling Parties agree to support or not oppose the terms of this Settlement in any additional proceedings before the Commission (as well as any subsequent appeals). In such situation, the Settling Parties agree not to take any positions adverse to or inconsistent with the Settlement or any adverse positions against each other with respect to the Settlement or the subject matters herein, on remand or in additional related proceedings before the Commission.

(h) If the Agreement is not approved in its entirety by the Commission, the Settling Parties agree that the terms herein shall not be admissible in evidence or discussed by any party in a subsequent proceeding. Moreover, the concurrence of the Settling Parties with the terms of this Agreement is expressly predicated upon the Commission's approval of the Agreement in its entirety without any material modification or any material condition deemed unacceptable by any Party and the Commission's approval of the application of the allocation factors for TDSIC expenditures reflected in Joint Exhibit D to the Settlement Agreement filed on February 19, 2016 in IURC Cause No. 44688 ("TDSIC Allocation"). If the Commission does not approve the Agreement in its entirety and the TDSIC Allocation, the Agreement shall be null and void and deemed withdrawn, upon notice in writing by any Settling Party within fifteen (15) business days after the date of the Final Order that any modifications made by the Commission are unacceptable to it. In the event the Agreement is withdrawn, the Settling Parties will request that an Attorneys' Conference be convened to establish a procedural schedule for the continued litigation of this proceeding.

(i) The positions taken by the Settling Parties in this Settlement shall not be deemed to be admissions by any of the Settling Parties and shall not be used as precedent, except as necessary to implement the terms of this Settlement. This provision shall survive termination/voiding of this Agreement.

(j) It is understood that this Settlement is reflective of a good faith negotiated settlement and neither the making of the Settlement nor any of its provisions shall constitute an admission by any Settling Party in this or any other litigation or proceeding except as necessary to implement or enforce this Settlement Agreement. It is also understood that each and every term of the Settlement Agreement is in consideration and support of each and every other term.

(k) The Settling Parties will support this Settlement before the Commission and request that the Commission expeditiously accept and approve the Settlement. This Settlement is a complete, interrelated package and is not severable, and shall be accepted or rejected in its entirety without modification or further condition(s) that may be unacceptable to any Settling Party.

(l) The Settling Parties will file this Settlement and testimony in support of this Settlement. Such supportive testimony will be agreed-upon by the Settling Parties and offered into evidence without objection by any Settling Party and the Settling Parties hereby waive cross-examination of each other's witnesses. The Settling Parties propose to submit this Settlement and evidence conditionally, and if the Commission fails to approve this Settlement in its entirety without any change or with condition(s) unacceptable to any adversely affected Settling Party, the Settlement and supporting evidence may be withdrawn and the Commission will continue to proceed to decision in the affected proceedings, without regard to the filing of this Settlement.

(m) The communications and discussions during the negotiations and conferences and any materials produced and exchanged concerning this Settlement all relate to offers of settlement and shall be privileged and confidential, without prejudice to the position of any Settling Party, and are not to be used in any manner in connection with any other proceeding or otherwise. This provision shall survive termination/voiding of this Agreement.

(n) The undersigned Settling Parties have represented and agreed that they are fully authorized to execute the Settlement on behalf of their designated clients, and their successors and assigns, who will be bound thereby.

(o) This Settlement may be executed in two (2) or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

ACCEPTED AND AGREED TO THIS 24th day of March, 2016:

[Signature pages to follow]

For Northern Indiana Public Service Company

Kathleen O'Leary, President
Northern Indiana Public Service Company

[This is a signature page for the 7-Year Plan and Transmission, Distribution and Storage Improvement Charge ("TDSIC") Settlement Agreement before the Indiana Utility Regulatory Commission in Cause No. 44733. Remainder of page intentionally left blank.]

For the Indiana Municipal Utilities Group:

Robert M. Glennon
Counsel For Indiana Municipal Utility Group

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For the Indiana Office of Utility Consumer Counselor:

A. David Stippler, Consumer Counselor
Indiana Office of Utility Consumer Counselor

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For LaPorte County Board of Commissioners

[This is a signature page for the 7-Year Plan and Transmission, Distribution and Storage Improvement Charge ("TDSIC") Settlement Agreement before the Indiana Utility Regulatory Commission in Cause No. 44733. Remainder of page intentionally left blank.]

NIPSCO Industrial Group:

Todd Richardson, Counsel
NIPSCO Industrial Group

[This is a signature page for the 7-Year Plan and Transmission, Distribution and Storage Improvement Charge ("TDSIC") Settlement Agreement before the Indiana Utility Regulatory Commission in Cause No. 44733. Remainder of page intentionally left blank.]

For United States Steel Corporation

[This is a signature page for the 7-Year Plan and Transmission, Distribution and Storage Improvement Charge ("TDSIC") Settlement Agreement before the Indiana Utility Regulatory Commission in Cause No. 44733. Remainder of page intentionally left blank.]