PROPOSED ORDER

FILED
December 19, 2014
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR (1) APPROVAL OF A TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENT CHARGE ("TDSIC") RATE SCHEDULE, (2) APPROVAL OF PETITIONER'S PROPOSED COST ALLOCATIONS (3) APPROVAL OF THE TIMELY RECOVERY OF TDSIC COSTS THROUGH PETITIONER'S PROPOSED TDSIC RATE SCHEDULE, (4) AUTHORITY TO DEFER APPROVED TDSIC COSTS, (5) APPROVAL OF THE METHODOLOGY USED TO CALCULATE THE 2% TEST, (6) APPROVAL OF AN ADJUSTMENT TO ITS GAS SERVICE RATES THROUGH ITS TDSIC RATE SCHEDULE, (7) AUTHORITY TO DEFER 20% OF THE APPROVED TDSIC COSTS FOR RECOVERY IN PETITIONER'S NEXT GENERAL RATE CASE, AND (8) APPROVAL OF PETITIONER'S UPDATED 7-YEAR GAS PLAN, INCLUDING ACTUAL AND PROPOSED ESTIMATED CAPITAL EXPENDITURES AND TDSIC COSTS THAT EXCEED THE APPROVED AMOUNTS, ALL PURSUANT TO IND. CODE CH. 8-1-39 AND THE COMMISSION'S ORDER IN CAUSE NO. 44403.	)	**CAUSE NO. 44403-TDSIC-1**

SUBMISSION OF PROPOSED ORDER

Northern Indiana Public Service Company ("NIPSCO"), by counsel, respectfully submits the attached form of proposed order.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by email transmission upon the following:

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Dated this 19th day of December, 2014.

Claudia J. Earls

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR (1) APPROVAL OF A TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENT CHARGE ("TDSIC") RATE SCHEDULE, (2) APPROVAL OF PETITIONER'S PROPOSED COST ALLOCATIONS, (3) APPROVAL OF THE TIMELY RECOVERY OF TDSIC COSTS THROUGH PETITIONER'S PROPOSED TDSIC RATE SCHEDULE, (4) AUTHORITY TO DEFER APPROVED TDSIC COSTS, (5) APPROVAL OF THE METHODOLOGY USED TO CALCULATE THE 2% TEST, (6) APPROVAL OF AN ADJUSTMENT TO ITS GAS SERVICE RATES THROUGH ITS TDSIC RATE SCHEDULE, (7) AUTHORITY TO DEFER 20% OF THE APPROVED TDSIC COSTS FOR RECOVERY IN PETITIONER'S NEXT GENERAL RATE CASE, AND (8) APPROVAL OF PETITIONER'S UPDATED 7-YEAR GAS PLAN, INCLUDING ACTUAL AND PROPOSED ESTIMATED CAPITAL EXPENDITURES AND TDSIC COSTS THAT EXCEED THE APPROVED AMOUNTS, ALL PURSUANT TO IND. CODE CH. 8-1-39 AND THE COMMISSION'S ORDER IN CAUSE NO. 44403.	)	**CAUSE NO. 44403-TDSIC-1** **APPROVED:**

ORDER OF THE COMMISSION

Presiding Officers:
Angela Rapp Weber, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

On August 28, 2014, Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") petitioned the Indiana Utility Regulatory Commission ("Commission"), pursuant to Ind. Code Ch. 8-1-39 and the Commission's April 30, 2014 Order in Cause No. 44403 ("7-Year Gas Plan Order") for: (1) approval of a Transmission, Distribution and Storage System Improvement Charge ("TDSIC") Rate Schedule, (2) approval of Petitioner's proposed cost allocation, (3) approval of the timely recovery of TDSIC costs through Petitioner's proposed TDSIC Rate Schedule, (4) authority to defer approved TDSIC costs, pursuant to Ind. Code Ch. 8-1-39, (5) approval of the methodology used to calculate the 2% test; (6) approval of TDSIC factors, (7) authority to defer 20% of the approved TDSIC costs, and (8) approval of NIPSCO's Updated 7-Year Gas Plan ("Updated Plan"). United States Steel Corporation ("U.S. Steel") and

NIPSCO Industrial Group ("Industrial Group")[1] filed petitions to intervene, both of which were subsequently granted.

On August 28, 2014, NIPSCO prefiled direct testimony of Frank A. Shambo, Vice President of Regulatory and Legislative Affairs, Mark G. Small, Director of Engineering, Kurt A. Sangster, Vice President of Major Projects; and Derric J. Isensee, Manager, Regulatory Support and Analysis in the Rates and Regulatory Finance Department. On October 24, 2014, NIPSCO filed revisions to Exhibit 1 and Exhibit 2 attached to the verified petition and Mr. Isensee's prefiled direct testimony and exhibits.

On October 30, 2014, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled direct testimony of Barbara A. Smith, Director of the Resource Planning and Communications Division, Edward R. Rutter, Utility Analyst in the OUCC's Resource Planning and Communications Division, and Mark H. Grosskopf, Senior Utility Analyst in the OUCC's Gas Division.

On October 30, 2014, the Industrial Group prefiled direct testimony of Nicholas Phillips, Jr., Managing Principal of Brubaker & Associates, Inc.

On October 31, 2014, NIPSCO filed revisions to its Exhibit Gas Plan Update-1 (Confidential) attached to the verified petition.

On November 19, 2014, the Industrial Group prefiled cross-answering testimony of Mr. Phillips. On that date NIPSCO prefiled rebuttal testimony of Frank A. Shambo, Mark G. Small, and Kurt A. Sangster. Also on that date, NIPSCO filed revisions to its Exhibit 1.

On December 4, 2014, the Commission issued a Docket Entry requesting that NIPSCO respond to questions, to which NIPSCO responded on December 5, 2014.[2] NIPSCO also filed corrections to the verified direct testimony of Mr. Sangster and to the rebuttal testimony of Mr. Shambo on December 5, 2014.

An evidentiary hearing was held on December 8, 2014, at 9:30 a.m. in the IURC Conference Center, Suite 220, Judicial Courtroom 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, the prefiled evidence of NIPSCO, the OUCC and Industrial Group were admitted into the record without objection. No member of the public appeared or participated at the hearing.

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

1. Notice and Jurisdiction. Notice of the hearing in this Cause was given and published by the Commission as required by law. Petitioner is a public utility as that term is defined in Ind. Code §§ 8-1-2-1(a) and 8-1-39-4. Under Ind. Code ch. 8-1-39, the Commission has jurisdiction over a public utility's petition to approve rate schedules establishing a TDSIC that will allow the periodic automatic adjustment of the public utility's basic rates and charges to

[1] The members of the Industrial Group in this proceeding are ArcelorMittal USA, BP Products North America, Inc., Chrysler Group, LLC and Praxair, Inc.

[2] NIPSCO filed a supplemental response to one of the Docket Entry questions on December 17, 2014.

provide for timely recovery of eighty percent of approved capital expenditures and TDSIC costs. Therefore, the Commission has jurisdiction over Petitioner and subject matter of this proceeding.

2. **Petitioner's Characteristics.** Petitioner is a public utility organized and existing under the laws of the State of Indiana and having its principal office at 801 E. 86th Street, Merrillville, Indiana 46410. 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. Petitioner provides gas utility service to more than 821,000 residential, commercial and industrial gas customers in Adams, Allen, Benton, Carroll, Cass, Clinton, DeKalb, Elkhart, Fulton, Howard, Huntington, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Miami, Newton, Noble, Porter, Pulaski, St. Joseph, Starke, Steuben, Tippecanoe, Tipton, Wabash, Warren, Wells, White and Whitley Counties in northern Indiana.

3. **Background and Relief Requested.** On October 3, 2013, Petitioner filed a Petition, docketed as Cause No. 44403, for approval of a 7-year plan for eligible transmission, distribution and storage system improvements ("7-Year Gas Plan"), pursuant to Ind. Code §§ 8-1-39-10 and 11. In its 7-Year Gas Plan Order, the Commission held: (1) the projects contained in Year 1 of NIPSCO's 7-Year Gas Plan are "eligible transmission, distribution, and storage system improvements" within the meaning of Indiana Code § 8-1-39-2; (2) the project categories contained in Years 2 through 7 of NIPSCO's 7-Year Gas Plan are presumed "eligible transmission, distribution, and storage system improvements" within the meaning of Indiana Code § 8-1-39-2, subject to further definition and specifics being provided through the plan update proceedings; (3) the 7-Year Gas Plan is reasonable and approved subject to the modifications within the Order; (4) NIPSCO's proposed definitions of key terms for purposes of interpreting and applying those terms to NIPSCO's Plan are approved; and (5) NIPSCO's proposed process for updating the 7-Year Gas Plan in future semi-annual adjustment proceedings is approved with its first TDSIC filing on September 1, 2014.

By its Petition, Petitioner requests the following relief in this proceeding:

- approval of Petitioner's proposed TDSIC Rate Schedule and accompanying changes to its gas service tariff which will allow for the timely recovery of 80% of eligible and approved capital expenditures and TDSIC costs and authorizing Petitioner to defer, until recovery through the TDSIC, 80% of the post in service TDSIC costs of the TDSIC projects, including carrying costs, depreciation and taxes;

- approval of Petitioner's proposal to use the customer class revenue allocation factor based on firm load approved in Petitioner's most recent retail base rate case order (Cause No. 43894);

- authorization to defer 20% of the eligible and approved capital expenditures and TDSIC costs in connection with its Commission-approved 7-Year Gas Plan for recovery in NIPSCO's next general rate case pursuant to Ind. Code § 8-1-39-9(b) and the 7-Year Gas Plan Order;

- approval of Petitioner's proposed method of calculating pretax return under Ind. Code § 8-1-39-13;

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

- approval of Petitioner's proposed method of calculating 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;

- authorization and approval of TDSIC factors to become effective for bills rendered by NIPSCO for the months of February 2015 through May 2015 or until replaced by different factors approved in a subsequent filing;

- approval of Petitioner's Appendix F – Transmission, Distribution and Storage System Improvement Charge, Original Sheet No. 157 of its IURC Gas Service Tariff, Original Volume No. 7, which contains the TDSIC factors to become effective for bills rendered by NIPSCO for the months of February 2015 through May 2015 or until replaced by different factors approved in a subsequent filing;

- approval of the Updated Plan, including actual and proposed estimated capital expenditures and TDSIC costs that exceed the amounts approved in Cause No. 44403; and

- approval to recover 80% of eligible and approved capital expenditures and TDSIC costs in connection with the Updated Plan through the TDSIC and authorizing Petitioner to defer 20% of eligible and approved capital expenditures and TDSIC costs in connection with the Updated Plan, for recovery in its next general rate case.

4. <u>Evidence Presented.</u> The evidence presented on three contested issues (112th Street Project, Bare Steel Projects and Rural Extensions Project) is summarized in Finding No. 5.a.(1) below.

a. <u>NIPSCO's Case-in-Chief.</u>

Frank A. Shambo provided testimony to support NIPSCO's request to establish a TDSIC Rate Schedule. He explained that NIPSCO is seeking to establish a TDSIC Rate Schedule and is seeking approval of a factor to recover costs associated with the 7-Year Gas Plan. Mr. Shambo explained that NIPSCO is requesting approval to use its customer class revenue allocation factor based on firm load that was approved in NIPSCO's November 4, 2010 Order in Cause No. 43894 ("2010 Rate Order") and that consistent with the Commission's Order in Cause No. 44371, NIPSCO is proposing that the cost of transmission system improvements be allocated among all customer classes consistent with the revenue allocation from the 2010 Rate Order, while distribution system improvement costs would not be allocated to transportation customers receiving service under Rates 428 and 438. He testified that costs associated with storage projects would be allocated in the same manner as distribution costs, and the cost of rural extension projects would be allocated in the same manner as transmission and distribution costs based on the character of the facilities installed.

Mr. Shambo testified that NIPSCO proposes that its pretax return be calculated using its weighted average cost of capital ("WACC") consistent with the methodology approved by the Commission for NIPSCO's 7-Year Electric TDSIC Tracker and as used for other capital trackers such as NIPSCO's electric Environmental Cost Recovery Mechanism ("ECR"). NIPSCO proposes to use 9.9% as the return on equity in the calculation of the pretax return for use in the TDSIC as approved in NIPSCO's most recent gas general rate proceeding.

Mr. Shambo explained that master meter remediation projects are projects to replace underground distribution facilities behind (or downstream of) "master" meters used to feed multiple customers, and that master meter arrangements have been identified as significant safety risks because the distribution facilities located behind the meter are not owned, operated, or maintained by NIPSCO or any other regulated utility. He testified that as a result NIPSCO is not able to verify compliance with the applicable design, construction and operational standards, and has proposed a seven year budget of $2 Million for the remediation of such arrangements in its 7-Year Gas Plan, but not identified specific master meter remediation projects that would be undertaken. After review by the Commission's Pipeline Safety Division, NIPSCO has identified specific master meter remediation projects it intends to complete to remediate these types of public safety risks consistent with the purpose of Ind. Code Ch. 8-1-39.

Derric J. Isensee testified that NIPSCO proposes to file its TDSIC petitions and cases in chief by September 1 and March 1 each year, with new rates becoming effective for the 6 month periods starting on December 1 and June 1, respectively. The petition filed on September 1 will be based on capital spend and expenses through the previous six month period ended June 30 while the petition filed on March 1 will be based on capital spend and expenses through the previous six month period ended December 31. The reconciliation of actual revenues will be completed on a 12 month lag. In accordance with Ind. Code § 8-1-39-9(a) and as required by the Commission's 44403 Order, NIPSCO will also provide a report on the progress of its 7-Year Gas Plan, including any changes such as scheduling changes, proposed project additions or subtractions, and proposed changes in cost estimates.

Mr. Isensee testified that NIPSCO proposes to recover 80% of TDSIC costs incurred with respect to eligible transmission, distribution, and storage system improvements incurred both while the improvements are under construction and post in service in accordance with Ind. Code § 8-1-39-9(a). He explained that costs will include, but not be limited to, depreciation expense, operations and maintenance ("O&M") expense, property taxes, pretax returns, allowance for funds used during construction ("AFUDC") and post in service carrying costs as set out in Ind. Code §§ 8-1-39-7 and 8-1-39-9(b). These costs will be recovered on a historical basis subsequent to the date in which the actual costs were incurred. While the statute permits the recovery of O&M expenses, consistent with NIPSCO's Approved Plan, the only O&M costs for which cost recovery is sought at this time are those associated with the approved project for the conversion of historical system records to a digital format for incorporation into NIPSCO's geographic information system and other electronic systems.

Mr. Isensee explained that NIPSCO proposes to implement Construction Work in Progress ("CWIP") ratemaking treatment related to the recovery of financing costs incurred during the construction of capital projects in accordance with Ind. Code § 8-1-39-9. Under CWIP ratemaking treatment, NIPSCO will recover, through the TDSIC, financing costs incurred during the construction period attributable to qualifying capital investments. Given that the financing costs under CWIP ratemaking are recovered as the capital costs are incurred (while the project is under construction), the customer is able to avoid the negative effects of compounding accrued AFUDC while the utility is able to avoid the negative effects of regulatory lag, including negative cash flows and earnings erosion. In connection with CWIP ratemaking, NIPSCO will cease accruing AFUDC the earlier of the date in which such expenditures receive CWIP ratemaking treatment through the TDSIC or the date the project is placed in service.

Mr. Isensee stated NIPSCO also proposes to recover 80% of all post in service carrying costs incurred in connection with projects approved as part of the 7-Year Gas Plan, through the TDSIC, with the costs determined based on NIPSCO's overall weighted cost of capital and will encompass all financing costs incurred from the in-service date until such projects receive ratemaking treatment.

Mr. Isensee testified that NIPSCO will calculate a revenue requirement in each semi-annual filing consisting of two components: (1) a return of financing costs related to capital expenditures including AFUDC, post in service carrying costs and pretax returns; and (2) recovery of depreciation expense, O&M and property tax expense associated with the approved TDSIC projects. NIPSCO will then multiply the total revenue requirement by 80% to establish the TDSIC revenue requirement. The return of financing costs related to capital expenditures will be calculated based on the actual TDSIC project costs, net of accumulated depreciation. AFUDC, a subcomponent of the capital costs, will be calculated in accordance with Generally Accepted Accounting Principles ("GAAP"), until such costs are given CWIP ratemaking treatment or are otherwise reflected in NIPSCO's basic rates and charges or the TDSIC projects are placed in service, whichever occurs first. He testified that NIPSCO will compute AFUDC amounts and relevant AFUDC rates for eligible TDSIC projects in accordance with the FERC or NARUC Uniform System of Accounts, which is consistent with GAAP. Post in service carrying costs will be calculated and included in the revenue requirement after such projects are placed in service and until such costs are given ratemaking treatment through the TDSIC or are otherwise reflected in NIPSCO's basic rates and charges.

Mr. Isensee testified that once the revenue requirement is calculated, NIPSCO will reduce the revenue requirement related to the recoverable post in service carrying charges and the pretax return to 80% in accordance with Ind. Code § 8-1-39-9(a). In future filings, the revenue requirement will also include the variance associated with the under or over collection of these costs due to the difference between the forecasted volumes used to calculate the rates and actual volumes billed. Finally, NIPSCO will gross-up the revenue requirement for all incremental taxes incurred as a result of the additional revenues.

Mr. Isensee explained NIPSCO's proposal to recover the depreciation expense, O&M expense and property tax expense on a historical basis, with six months of actual expense included in each adjustment proceeding after such costs have been incurred. Once calculated, NIPSCO will reduce the revenue requirement related to the recoverable expenses to 80% in accordance with Ind. Code ch. 8-1-39. In future filings, the revenue requirement will also include the variance associated with the under or over collection of these costs due to the difference between the forecasted volumes used to calculate the rates and actual volumes billed.

Finally, NIPSCO will gross-up the revenue requirement for all incremental taxes incurred as a result of the additional revenues.

Mr. Isensee clarified that NIPSCO is proposing one change to the ratemaking methodology approved by the Commission in NIPSCO's electric proceeding. He noted that the rate on customer deposits used to calculate the overall WACC is fixed on the electric side of NIPSCO's business at the cost approved in Cause No. 43969, which is appropriate because that rate represented a blended cost as of the test period, utilizing the fixed electric deposit rate and the then effective gas deposit rate. Because the gas rate paid on customer deposits is updated by the Commission, NIPSCO proposes to use an updated deposit rate in its calculation of the recovery of financing costs for this gas proceeding.

Mr. Isensee also explained that NIPSCO proposes to defer and recover 80% of the post in service costs, including carrying costs and pretax returns, depreciation, O&M and property tax expense associated with its approved TDSIC projects, through the TDSIC adjustment factor. NIPSCO proposes to defer such costs as a regulatory asset until such costs are recognized for ratemaking purposes through NIPSCO's proposed TDSIC adjustment factor or included for recovery in NIPSCO's basic rates and charges in its next general rate case.

With respect to the deferral of unrecovered TDSIC costs, Mr. Isensee explained that Ind. Code § 8-1-39-9(b) provides that 20% of the approved capital expenditures and TDSIC costs, including depreciation, pretax returns, AFUDC, post in service carrying costs, O&M and property taxes shall be deferred and recovered by the public utility as part of the next general rate case filed by the public utility with the Commission. He said that, NIPSCO accordingly requests approval to defer, as a regulatory asset, 20% of such costs including depreciation, pretax returns, post in service carrying costs, O&M and property tax expenses and requests to recover those costs as part of NIPSCO's next general rate case, and approval to record ongoing carrying charges based on NIPSCO's WACC on these costs until the costs are included for recovery in NIPSCO's basic rates and charges in that future case.

Mr. Isensee testified that NIPSCO proposes to depreciate the TDSIC capital expenditures according to each asset's designated FERC account classification, and that upon being placed in service, each asset will depreciate according to the FERC account composite remaining life approved by the 2010 Rate Order.

Mr. Isensee testified that if NIPSCO incurs TDSIC costs under the 7-Year Gas Plan that result in a revenue requirement that would exceed the percentage increase in a TDSIC approved by the Commission, NIPSCO will defer such costs as a regulatory asset for recovery by the public utility as part of the next general rate case filed with the Commission. He stated "retail revenues" used in this calculation will be obtained from NIPSCO's "Operating Revenues" from the most recent earnings test in NIPSCO's Gas Cost Adjustment proceeding. This methodology is the same as the methodology approved by the Commission for NIPSCO's electric TDSIC in Cause No. 44371. He stated NIPSCO does not anticipate exceeding the 2% cap under the Updated 7-Year Gas Plan.

Mr. Isensee testified that NIPSCO proposes to increase the authorized net operating income approved in the Commission's August 28, 2013 Order in Cause No. 43894 ("2013 Rate Order") to include the earnings associated with the TDSIC projects for purposes of the Ind. Code § 8-1-2-42(g) earnings test, consistent with the way earnings associated with NIPSCO's qualified pollution control property and clean coal technology are treated on the electric side of NIPSCO's operations, and also consistent with the Commission's Order in Cause No. 44371 approving NIPSCO's Electric TDSIC and with Ind. Code § 8-1-39-13(b). He explained that also consistent with the Order in Cause No. 44371, NIPSCO has calculated the 2% cap by comparing the incremental TDSIC revenues above the last approved TDSIC with the total retail revenues for the past 12 months. The retail revenues used in this calculation represent the revenues related to the 12 months ended June 30, 2014 obtained from the Income Statement in Schedule 16 filed in support of Cause No. 43629-GCA-31.

Kurt W. Sangster presented testimony that addressed the status of the 7-Year Gas Plan Deliverability project involving the replacement of the feed from Natural Gas Pipeline of America ("NGPL") to NIPSCO's 112th Street Station (the "112th Street Project"), including updates to the projected cost. His testimony also addressed project management aspects of the extension of facilities to serve rural customers.

Mark G. Small sponsored NIPSCO's Updated Plan as required by Ind. Code § 8-1-39-9 (Revised Exhibit Gas Plan Update-1 (Confidential)) and specifically addressed updated cost estimates for several of the projects included in that Updated Plan.[3] He testified that the Updated Plan remains focused on Gas Transmission, Distribution, Storage, and related Gas System Integrity Data and Technology investments made for safety, reliability, system modernization or economic development with the overarching goal to make necessary investments that enable NIPSCO to continue providing safe, reliable gas service to its customers into the future.

Mr. Small explained that like the Approved Plan, the Updated Plan is comprised of four segments: (1) investments aimed at maintaining the system reliability through the capacity of the system to deliver gas to customers when they need it (Gas System Deliverability); (2) replacement of certain system assets to ensure the ongoing integrity and safe operation of the gas system (Gas System Integrity); (3) data and technology investments required for the gas system integrity program (System Integrity Data Integration); and (4) the extension of gas facilities into rural areas (Rural Gas Extensions). He testified that the Updated Plan provides a comprehensive update to the Approved Plan that incorporates the results of an updated risk model and project prioritization, an update to the projects that NIPSCO is performing in Year 1 (the "2014 Projects") and specific detail for projects that NIPSCO will perform in Year 2 (the "2015 Projects") under the Updated Plan, and an update to annual projected expenditures for the remaining years of the Plan in 2016 through 2020.

Mr. Small testified the Updated Plan includes a detailed listing of the projects and projected costs associated with each project and compares the cost projections in the Approved Plan, by asset class, with the current cost projections shown in the Updated Plan along with a brief explanation of the variance. He noted that this approach is intended to comply with the requirement in the 7-Year Gas Plan Order requiring this comparison in a format similar to that used in NIPSCO's ECR filings. He testified that the estimated capital cost of the Updated Plan is $862.2 million, including indirect capital and AFUDC, and that the total estimated O&M cost of the Updated Plan is $8.5 million, and included the following table comparing the Approved Plan to the Updated Plan:

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[3] Revised Exhibit Gas Plan Update-1 (Confidential) is an update to Petitioner's Exhibit No. MGS-1 (Confidential) approved in Cause No. 44403. NIPSCO intends to follow this naming convention in subsequent updates to its 7-Year Gas Plan to enable comparison and eliminate confusion.

NIPSCO's Projected Annual Expenditures
(in millions)

	Year 1 2014	Year 2 2015	Year 3 2016	Year 4 2017	Year 5 2018	Year 6 2019	Year 7 2020	Total
7-Year Gas Plan								
Capital	$53.3	$89.2	$109.4	$113.6	$117.8	$113.7	$116.1	$713.1
O&M	$2.5	$3.0	$3.0					$8.5
Updated 7-Year Gas Plan								
Capital	$66.9	$120.7	$128.3	$134.8	$138.9	$134.6	$138.0	$862.2
O&M	$2.5	$3.0	$3.0					$8.5
Change	**$13.6**	**$31.5**	**$18.9**	**$21.2**	**$21.1**	**$20.9**	**$21.9**	**$149.1**

Mr. Small sponsored Petitioner's Exhibit No. MGS-1 (Confidential) (the "Risk Model Update") prepared by EN Engineering in support of the Updated Plan, showing the updated risk-based modeling used to identify and prioritize the transmission pipeline replacement projects in the Gas System Integrity segment of the Updated Plan. He stated that NIPSCO did not utilize EN Engineering to identify or prioritize any distribution or storage system projects in the Gas System Integrity segment of the Updated Plan. He testified the projects and estimates included in the Updated Plan for Gas System Deliverability, System Integrity Data Integration or the Rural Gas Extension investments were identified and ranked by NIPSCO.

Mr. Small explained that while the annual cost of the 7-Year Gas Plan is projected to increase in each year of the Plan, two projects (the 112th Street Project and the extension of service into unserved rural areas) make up the vast majority of the overall increase in the projected cost of the Plan and that the projected costs of other projects in the Plan have not changed either individually or in the aggregate to the same degree. He testified that while it is not possible to know how future events will unfold, two factors make similar cost escalation unlikely. First, the time restrictions associated with the 112th Street Project limited NIPSCO's ability to take commercial steps to limit the exposure to cost escalation -- not the case for the majority of the projects in the Updated Plan. Second, the increase in costs associated with the rural extension projects was driven by the need to incorporate all rural extensions, not just those that would not have been made but for the expanded 20-year margin test authorized by Ind. Code § 8-1-39-11 -- circumstances unique to rural extension projects and inconsistent with the large transmission projects that make up the majority of the remaining projects in the Updated Plan. Mr. Small testified that the cost estimates for all of the transmission pipeline replacement projects in the 7-Year Gas Plan were re-examined by EN Engineering at NIPSCO's request as a result of the variance with the 112th Street Project and incorporated in the Updated Plan. He also explained that indirect costs and AFUDC increased by approximately $25 Million during the life of the Plan primarily due to the revised approach to rural extensions that includes costs associated with extensions to all rural customers.

Mr. Small testified that one additional transmission, distribution, and storage system improvements project has been identified that may have to be completed by the end of 2015 if it becomes necessary to undertake. He explained that the project involves the potential need to replace a feed from NGPL at NIPSCO's current 134th St. take point and that NIPSCO may undertake preliminary engineering work to assess feasibility of potential solutions to the issue.

He testified that due to uncertainty about whether the project will be required and if so at what cost, it had not been included in the Updated Plan based on time constraints associated with the filing.

Mr. Small also provided updates on the status of several projects in the Approved Plan including shallow pipe remediation, bare steel replacement, in-line inspection ("ILI") capability enhancement, inspect and mitigate projects, master meter remediation, system data integration and rural extensions. Of those projects, he provided testimony about increases in the Updated Plan associated with bare steel replacement, inspect and mitigate and rural extension projects, and testified that the Updated Plan incorporated decreases in the projected budgets for shallow pipe transmission projects and ILI projects.

Mr. Small testified that as engineering for the shallow pipe transmission projects proceeded, it was determined that the prudent path forward was to eliminate projects on shallow transmission pipe segments that were already scheduled to either be retired or significantly reduced in operating pressure as part of the Plan. He stated that this approach was validated by new data received from a transmission pipe depth survey conducted by NIPSCO in 2014 that determined that significant sections of NIPSCO's 22" pipeline were currently too shallow based on the transmission pipeline design depth of 48". NIPSCO determined that spending significant resources to lower small sections of the pipe or attempting to lower very large sections of the pipe was neither practical nor a cost effective solution. He explained that as a result, three of the four projects were eliminated from the 2014 plan resulting in a decrease of $3,352,806.

Mr. Small testified that since the preparation of the 7-Year Gas Plan, NIPSCO engaged an engineering-planning-construction vendor experienced with ILI projects to assist in the preparation of an ILI feasibility analysis for the pipeline systems to be retrofitted for ILI capabilities. The NIPSCO Transmission Integrity Management Program ("TIMP") staff has identified specific ILI projects for the Plan that will be completed for retrofitting based on these preliminary reviews resulting in a decrease in the number of projects in the Updated Plan compared to the Approved Plan resulting in a reduction in cost of approximately $10 Million in Years 5 through 7 of the Plan (2018-2020). He explained that NIPSCO will continue to refine its ILI project listing and projected costs for the out years of the Plan may be further updated as that process progresses.

Mr. Small testified the distribution system Inspect and Mitigate projects consist of projects that are identified through ongoing inspection programs conducted by the NIPSCO Gas Operations group and accommodate the replacement of facilities based on conditions encountered in the field. He explained that an increase of approximately $5.1 Million over the 7-year Plan is warranted based on an anticipated increase in distribution regulator stations requiring replacement based on data from recent field inspections and regulator station replacements. Mr. Small stated that as NIPSCO captures data from ongoing inspections done by field crews, lists of prioritized projects are developed to optimize compliance and continue operation of a safe infrastructure. He explained Field Operations teams complete annual inspections on each regulator to ensure safe operation, and also complete a full mechanical inspection on a 5-year interval, and that data from these inspections is reviewed by operations and integrity groups to drive the capital asset replacement, based on a comprehensive comparison of data on leaks, corrosion, obsolete design, etc. He testified that the current list of regulator stations in need of replacement is included in 2015 and 2016 as part of the Inspect and Mitigate budget in the Updated Plan.

Mr. Small testified that master meter remediation projects involve the replacement of high-risk underground gas facilities behind master meters, and the reconfiguration of those systems to minimize the safety risk. He explained that while the overall cost associated with these projects has not changed, the timing has. He testified that NIPSCO has been working with the Pipeline Safety Division to identify the master meter systems in its service territory with the highest priority for replacement, and that in order to get the identified projects engineered and needed construction resources arranged, the planned expenditure for these projects in 2014 has been moved out to 2015 in the Updated Plan, but that the cost over the life of the Plan remains at the original estimate of $2,000,000.

Mr. Small testified the Updated Plan still includes a total of $8.5 Million in costs associated with the research of legacy paper records, and the integration of that data into NIPSCO's GIS system. He explained that NIPSCO has progressed with the initial steps in converting system integrity data from disparate paper records and individual databases into the corporate GIS prior to approval of the 7-Year Gas Plan by contracting for the scanning and indexing of approximately 71,000 linens and the indexing of 900,000 service cards. He testified that while portions of the conversion process began prior to the approval of the Plan, the balance of expenditures have been incorporated into the Updated Plan beginning in mid-2014. NIPSCO anticipates performing several major activities in 2014 including overall data assessment, pre-conversion development of a source data matrix, GIS architecture refinements, service card viewer enhancements, grid mapping of GIS, data model design and GIS platform roadmap, the completion of the pilot conversion process, and the transmission pipe center-line addition to GIS. He explained that commencing in January 2015 the full conversion project will factor in the preparatory work completed in 2014 incorporating the information gleaned from the linens and service cards into a single data source that fully and accurately portrays the information necessary to make prudent decisions with respect to pipeline safety.

Mr. Small testified that major activities associated with the System Data Integration project spanning the 2015 to 2016 time frame will include conversion of relevant information from linens and service cards into GIS or MAXIMO (as appropriate), migration of corrosion data contained within GC Client, reconciliation of emergency valves identification and location, completion of regulator station data, migration of leak rate survey data into MAXIMO, the enabling and application of emergency isolation areas feature within GIS, synchronization of GIS and MAXIMO, migration of data from GIS Web, integration of System Planning Model into GIS, and the integration of Blue Buried Metallic Pipe Cards. He stated that the System Data Integration Project will result in GIS attribute updates for both transmission and distribution assets, and that NIPSCO expects to allocate costs for this project to distribution and transmission using the ratio of the pipe types on the system. Mr. Small testified that the Updated Plan does not reflect any changes in cost or scope for the System Data Integration project at this time, but that the conversion of analog records and incorporation into NIPSCO's digital systems is a very complex process and that greater clarity around project scope and costs can be expected following pre-conversions workshops and pre-production demonstration projects scheduled for completion in December, 2014.

b. OUCC's Case-in-Chief.

Barbara A. Smith presented the OUCC's recommendations regarding NIPSCO's bare steel and 112th Street projects as well as the OUCC's review of other project changes. Ms. Smith testified the OUCC recommends that the Commission emphasize that the "best" estimate requirement in the Statute should not be taken lightly, and because NIPSCO did not fulfill its responsibility by sufficiently reviewing a third party estimate for an upcoming year project, it in essence removed the ratepayer protection built into the Statute for requiring the "best" estimates. She testified that the OUCC recommends the Commission deny NIPSCO's request to increase the TDSIC budget and deny NIPSCO cost recovery through the tracker for any amount over the original estimate for the 112th Street Project. She testified NIPSCO may include any actual 12th Street Project expenses over $3,322,780 in its next base rate case for cost recovery consideration by the Commission.

Ms. Smith also questioned why NIPSCO did not perform the shallow pipe analysis prior to its inclusion as a Year 1 project. She stated that while genuine project cost reduction is welcomed, the total 7-Year Plan budget still includes the $3,352,806 amount which can be transferred to other yet-to-be-defined projects now that the 7-Year Plan is approved, and NIPSCO failed to specify any additional O&M that will need to be spent on the mitigation as part of its case-in-chief. Finally, Ms. Smith testified the OUCC appreciates that NIPSCO is waiting until it has the master meter project details defined before moving forward and is pleased that NIPSCO is consulting with the Pipeline Safety Division with respect to those projects.

Mark H. Grosskopf testified he is in agreement with the revised calculations included within the schedules presented by NIPSCO witness Isensee, and recommended approval of NIPSCO's rate factor calculation methodology, subject to exceptions for (1) customer class revenue allocations, and (2) calculation of total rate adjustment factors to accommodate his recommendation concerning customer margins associated with rural extensions. Mr. Grosskopf recommended approval of NIPSCO's TDSIC rate factor calculation methodology with the following exceptions:

(1) the allocation percentages applied to distribution costs should be the same as the allocation percentages applied to transmission costs in this TDSIC filing, consistent with Petitioner's last rate case and consistent with Ind. Code § 8-1-39(a)(1);

(2) actual costs submitted for recovery in subsequent TDSIC filings should not be considered approved before the OUCC has had an opportunity to review these costs in the context of a TDSIC tracker petition for recovery;

(3) a revision should be made to the 2% Retail Revenue Cap Test calculation on Petitioner's Exhibit 1, Schedule 8, if necessary, depending on the outcome of the appeal currently pending in NIPSCO's Cause No. 44371;

(4) netting investments in new capital by the net book value of replaced assets included in the last base rate case should be done, depending on the outcome of the appeal currently pending in NIPSCO's Cause No. 44371;

(5) depreciation expense should be calculated on net approved TDSIC additions, such that if the new investments result in retirement of existing assets, depreciation expense included

in the revenue requirement will be reduced by the depreciation expense amount attributed to those retired assets once the depreciation credit in NIPSCO's current rates expires;

(6) Petitioner's proposed 80% credit of actual margins associated with new customers connected through rural extensions should be approved;

(7) the remaining 20% margin revenue from rural extensions should be deferred and used as a credit to the 20% TDSIC revenue deferred over the same period, for a net revenue recovery in the next rate case; and

(8) the per therm TDSIC factors calculated on page 7, column (L) of OUCC Exhibit MHG-2 should be approved for recovery in this TDSIC filing.

Mr. Grosskopf testified this proceeding is the first of a series of TDSIC filings which he believes complies with the periodic filing requirements of Ind. Code § 8-1-39-9(a). He testified that while it is acceptable and necessary for NIPSCO to record the costs and expenditures for 7-Year Gas Plan projects that have been approved by the Commission for subsequent recovery through a TDSIC filing it is his position that the actual costs submitted for recovery in subsequent TDSIC filings should not be considered approved before the OUCC has had an opportunity to review these costs in the context of a TDSIC tracker petition for recovery, with comprehensive testimony and exhibits supporting such costs. He stated that the Commission would then render a decision on whether or not these costs may be recovered.

Mr. Grosskopf testified that NIPSCO's proposed allocation of TDSIC distribution costs deviated from the allocation method approved in the last rate case, and changes the allocation of distribution system improvement costs significantly. He stated that the allocation of distribution costs to residential customers would be 73.19% rather than the 66.82% approved in the last rate case. Mr. Grosskopf supported his assertion through reference to the cost of service study filed by NIPSCO witness Ronald Amen in NIPSCO's 2010 Rate Case that proposed to allocate a portion of distribution costs to transportation customers. Mr. Grosskopf recommended NIPSCO's TDSIC calculation be amended so that TDSIC distribution costs are allocated to each rate class using the same allocation percentage as applied to transmission costs on Petitioner's Exhibit 2, Schedule 4, with the corrected distribution allocations applied to Petitioner's Exhibit 1, Schedule 7, Column (D). In contrast to distribution costs and consistent with Mr. Amen's cost of service study, Mr. Grosskopf recommended that storage costs be allowed as currently proposed by NIPSCO in Petitioner's Exhibit 2, Schedule 4.

Mr. Grosskopf testified Exhibit 1, Schedule 9 will accomplish the task of tracking deferred capital expenditures and costs until recovery in Petitioner's next base rate case but that because of his recommendation regarding revenue margin credits, this schedule will either need revision or a separate revenue margin credit tracking schedule will be necessary. Mr. Grosskopf agrees the margin credit balances the interests of the utility and the ratepayers, and agrees that the absence of a margin credit on rural extensions would be a significant oversight in TDSIC cost recovery for any other utility collecting TDSIC cost recovery revenue on rural extension investments. He recommends approval of NIPSCO's proposed 80% margin credit for rural extensions for each TDSIC filing.

Mr. Grosskopf disagreed with NIPSCO's calculation of depreciation expense for recovery in the TDSIC. He stated Petitioner's Exhibit 1, Schedule 4, only accommodates reporting depreciation expense for approved TDSIC capital additions and should also account for depreciation expense on the asset retirements resulting from the approved TDSIC capital additions. He stated that depreciation expense on capital additions should be offset by depreciation expense on the capital retirements resulting from those additions. He testified that NIPSCO currently has a unique situation regarding depreciation expense and that because of a depreciation credit agreed to in settlement in the last rate case, NIPSCO's current rates do not include depreciation expense on its gas assets. He concluded that netting depreciation expense for these retired assets is un-necessary in this case, but that when the depreciation credit included in NIPSCO's current base rates expires, the net reduction of depreciation expense for retired assets will again be an issue for the OUCC.

Edward R. Rutter testified NIPSCO's updated 7-Year Gas Plan includes projects from the Approved Plan and that some project estimates originally scheduled for the first year have been delayed, accelerated, or modified based on either a change in scope or a change in unit price. He presented the OUCC's recommendations regarding the Updated Plan. The OUCC recommends approval of the Updated Plan as modified to reflect removal of $37,392 from total net investments in transmission, distribution and storage system improvements (expenditures incurred prior to the May 1, 2014 cutoff date); removal of $107,000 in O&M expense for non-TDSIC capital work recommended by Mr. Grosskopf; and removal of the cost estimates recommended by Ms. Smith in disallowing a portion of the bare steel replacement project and the 112th Street Project.

c. <u>Industrial Group Case-In-Chief.</u>

Nicholas Phillips, Jr. was critical of NIPSCO's proposed plan because it would add more than twice the amount of original cost rate base from its last rate case in Cause No. 43894, and testified that ratemaking implications are associated with a tracker that basically triples a utility's rate base. Mr. Phillips explained the historical background of NIPSCO's rates and the decline in its original cost rate base during the 20 year period prior to its last rate case. He testified that there had been a deficit in capital additions over time that together with NIPSCO's high depreciation rates had reduced its original cost net plant and rate base from 1988 to 2008.

Mr. Phillips testified that new depreciation rates were approved as part of its last rate case based on a NIPSCO sponsored depreciation study which lowered its depreciation rate from 5.5% to 1.58%, and implemented an agreed depreciation credit equal to the amount of its gas service depreciation expense to help close the gap between the book value of NIPSCO's gas assets and their remaining useful life, with new capital additions as the most significant factor in closing that gap.

Mr. Phillips contended that the special circumstances from NIPSCO's 2010 rate case order should be considered in connection with approving the Updated Plan and the TDSIC tracking mechanism.

Mr. Phillips testified that the Settlement approved in the 2010 Rate Order authorized a rate of return of 5.49% on NIPSCO's fair value rate base with a 7.0% rate of return on common equity. He also testified that NIPSCO earned more than its authorized return based on recent GCA filings, and calculated a total rate of return of 14.6% on its original cost rate base for the 12 months ended June 30, 2014.

Mr. Phillips was supportive of NIPSCO's proposed allocation methodology of TDSIC costs, and explained that while the allocation of TDSIC distribution costs only to distribution customers was not the same as the revenue allocation used in its last rate case, the Industrial Group does not object to the proposed methodology because transportation customers do not use distribution mains. He also supported the use of rural extension margins as an offset to TDSIC costs and recommended similar treatment for all margins in excess of those used for ratemaking in NIPSCO's last base rate case.

Mr. Phillips recommended that:

(1) NIPSCO not be allowed to layer an original cost approach to the special ratemaking based on a fair value rate of return used to establish the current base rates;

(2) the fair value rate of return of 5.49% found appropriate in the Commission's 2010 Rate Order should be used for capital investments in this cause;

(3) the Commission should limit NIPSCO's 7-Year Plan to a 100% increase in rate base ($318 million);

(4) NIPSCO's allocation of TDSIC costs to classes is reasonable and should be adopted;

(5) NIPSCO's proposal to provide a credit for new margin should be expanded to include increased sales and margins from the level used to design rates in the last base rate case, from each rate class; and

(6) NIPSCO should not be allowed to recover the costs in excess of its estimate for the 112th Street Project.

d. <u>NIPSCO's Rebuttal.</u>

Mr. Shambo disagreed with Mr. Grosskopf's assertion that "depreciation expense on [TDSIC] capital additions should be offset by depreciation expense on the capital retirements resulting from those additions[ ]". He explained that NIPSCO's base rates for gas service do not recover depreciation expense on gas assets as a result of the Commission-approved settlement in Cause No. 43894 resulting in no depreciation expense to include as an offset. Mr. Shambo added that the Commission rejected that approach in NIPSCO's electric TDSIC tracker proceeding in Cause No. 44371, and noted that the issue is currently pending before the Indiana Court of Appeals. He also testified that no statutory change or change in circumstances had occurred that would support a change in the Commission's determinations in Cause No. 44371.

Mr. Shambo also disagreed with Mr. Grosskopf's assertion that transportation customers taking service from transmission facilities under Rates 428 and 438 should be allocated costs associated with distribution related TDSIC projects. He explained that Mr. Grosskopf inappropriately relied on the cost of service study prepared by NIPSCO witness Ronald Amen in Cause No. 43894 because the rates approved by the Commission in that Cause were not based on Mr. Amen's study but rather reflected a percentage reduction to the then effective rates. He also noted that NIPSCO's proposal to exclude an allocation of distribution-related TDSIC costs for transportation customers is consistent with the approach approved by the Commission for NIPSCO's electric TDSIC in Cause No. 44371 – an issue currently pending before the Indiana

Court of Appeals. He explained that NIPSCO's proposed treatment of gas TDSIC distribution costs was a reasonable method to accomplish the alignment of the cost causation with cost allocation because those customers did not benefit from distribution assets.

Mr. Shambo also addressed Mr. Phillips' recommendation that cost recovery for investments in the 7-Year Gas Plan be capped at $318 Million. He testified that the Commission rejected the identical recommendation from Mr. Phillips in approving NIPSCO's 7-Year Gas Plan in Cause No. 44403 (44403 Order at 20), and that Mr. Phillips offered no additional evidence in support of his recommendation that was previously denied by the Commission.

Mr. Shambo disagreed with Mr. Phillips that NIPSCO's pretax return should be calculated based on a 5.49% fair value return or a 7.00% cost of equity because he had fundamentally misstated the premise of the rates established in the rate settlement in Cause No. 43894. He testified the return component of the *Stipulation and Settlement Agreement* in that cause used a pre-inflation 9.9% ROE adjusted downward using a 2.9% inflation reduction to result in a 7.0% ROE that, in combination with NIPSCO's capital structure as of December 31, 2009 and actual debt costs, was used to derive a 5.49% overall return on a fair value basis.

Mr. Shambo testified that the 7.0% advocated by Mr. Phillips is not an appropriate ROE for use in establishing the return for new TDSIC infrastructure investments because it inappropriately incorporates a 2.9% downward adjustment for inflation for purposes of settlement. He explained that inflation can by definition only be measured over the passage of time, and thus cannot be an appropriate consideration in determining the return on an asset from the day it is installed. He said Mr. Phillips' recommendation is flawed and results in an understated pretax return by incorrectly discounting the return based on an inapplicable inflation adjustment.

Mr. Shambo reiterated that the correct ROE to use from the *Stipulation and Settlement Agreement* approved in the Commission's 2013 Rate Order is 9.9% as used by NIPSCO, not 7.0% as Mr. Phillips incorrectly proposes. He testified that Mr. Phillips correctly notes that the original cost and fair value of capital investments are equal at the time the assets are placed in service. It is therefore appropriate to use the approved ROE from the *Stipulation and Settlement Agreement* that was the basis for the calculation of the fair return and is accordingly an accurate reflection of the return appropriate for new capital investments.

e. Industrial Group Cross-Answering Testimony.

Mr. Phillips sponsored cross-answering testimony that addressed the OUCC's recommendations relating to the customer class revenue allocation. He testified that Mr. Grosskopf's recommendation to allocate TDSIC distribution costs to transportation customers was unfair and completely at odds with cost of service principles. He recommended that NIPSCO's proposed allocators best reflect both cost causation and cost of service, and the result of NIPSCO's last base rate case. He stated that customers served by high pressure transmission systems do not use the lower pressure distribution mains and should not be allocated the costs of new distribution investment.

Mr. Phillips contested Mr. Grosskopf's reliance on the cost of service study filed by NIPSCO in Cause No. 43894 because it was not approved or used as the basis for revenue allocation in that case. He added that NIPSCO's filed cost of service (and NIPSCO's proposed revenue allocation) demonstrated that residential rates should be increased, but the fact that the residential class received a rate decrease confirms that NIPSCO's cost of service was not used as a basis for revenue allocation. He also noted that Mr. Amen's study in Cause No. 43894 used a fair value rate base of $1.938 billion while the original cost rate base was $318 million, yet the fair value rate base approved by the Commission was $725.7 million – further bolstering his contention that the study was not the basis for revenue allocation in the settled case.

Mr. Phillips testified that Mr. Grosskopf's contention that the Settlement Agreement did not exclude the allocation of distribution costs based on the number of customers does not translate into an agreement to do anything, and that silence in the Settlement Agreement does not constitute agreement on that issue. He testified that Mr. Grosskopf's conclusion that distribution costs should still be allocated on the basis of number of customers does not logically follow and should be rejected.

Mr. Phillips testified that new distribution investment allowed to be tracked in-between rate cases should only be allocated to distribution customers consistent with the manner that NIPSCO has proposed in its filing. He stated that NIPSCO's general overview indicates it plans that approximately 17.2% of its investments will be distribution related, 51.2% transmission related and 30.4% for rural extensions. He explained that because these investments can be separately identified, there is no need and it would be inappropriate to use a total cost allocation factor as suggested by Mr. Grosskopf. In fact, use of such an allocation factor will blatantly over-allocate costs to high pressure transmission customers. He stated that NIPSCO's approach to not charge high pressure transmission customers on Rates 428 and 438 with low pressure distribution system cost is appropriate because high pressure transmission customers on these rates do not use the distribution system in the delivery of gas. Thus, these customers should not be charged with costs associated with enhancements to the distribution system, which they do not use.

5. <u>Commission Discussion, Findings and Conclusions</u>. Given the interrelationship of issues presented for our review, our analysis first considers Petitioner's Updated 7-Year Plan, then addresses Petitioner's proposed TDSIC adjustment methodology and proposed TDSIC-1 factor.

a. <u>Findings and Conclusions Regarding Updated 7-Year Plan.</u>

Ind. Code § 8-1-39-9(a) requires a utility to update its 7-Year Plan with each TDSIC petition the utility files, a requirement also echoed in our Order approving Petitioner's initial 7-Year Gas Plan in Cause No. 44403. In that proceeding we found that

> Thus, in the context of our approval of NIPSCO's 7-Year Gas Plan, we will presume the categories of spending identified in the Plan for Years 2 through 7 are eligible for TDSIC treatment. Because we expect these eligible project categories will become better defined in terms of specificity as their respective investment year comes of age, provided the specific projects fall within the approved project categories, this presumption of eligibility will be assigned to specific projects in the annual updating process as further described below.

* * * *

> In accordance with Mr. Shambo's testimony, the Commission finds it reasonable that NIPSCO make its TDSIC filings every six months beginning September 1, 2014. The September filing shall provide project detail similar to Year 1 of the original 7-Year Gas Plan for the next upcoming year of the Plan. NIPSCO shall also update the required annual spends for the remaining years of the 7-Year Gas Plan, including the amount for the rural gas extensions segment.

44403 Order at 24 and 25. In this case, NIPSCO requests approval of its Updated Plan, including actual and proposed estimated capital expenditures and TDSIC costs that exceed the amounts approved in Cause No. 44403. The Updated Plan was attached to the Verified Petition as <u>Revised Exhibit Gas Plan Update-1 (Confidential)</u>. The Updated Plan is largely consistent with the 7-Year Plan we approved in Cause No. 44403 pursuant to Ind. Code § 8-1-39-10, and contains updates of cost estimates for Year 1 (2014 projects), a comprehensive overview of all proposed projects, by project category and by Gas FERC Account for all 7 years of the Plan, and a detailed project list and cost estimates for Year 2 (2015 projects), and a revised project risk ranking. We will review NIPSCO's Updated Plan in the context of Ind. Code § 8-1-39-10.

Ind. Code § 8-1-39-10 permits a public utility to petition the Commission for approval of the public utility's 7-year plan for eligible transmission, distribution, and storage improvements. Ind. Code § 8-1-39-10(b) identifies findings that must be made:

> (1) A finding of the best estimate of the cost of the eligible improvements included in the plan.
>
> (2) A determination whether 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 the 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.*

(1) <u>Best Estimate of the Cost of the Eligible Improvements</u>.

NIPSCO presented extensive and detailed evidence supporting its cost estimates contained in its Updated Plan, including instances of both increases and decreases in projected project costs. Three issues were raised in this proceeding that potentially impact our determination of whether the Updated Plan includes a best estimate of the cost of eligible improvements: (1) the increase in cost for the Rural Extension Projects, (2) the increase in cost for the 112th Street Project, and (3) the increase in cost for the bare steel replacement projects. We note that no party submitted evidence proposing that the estimates for those projects contained in the Updated Plan do not constitute a "best estimate" in the context of Ind. Code § 8-1-39-10(b)(1). Specifically, OUCC witness Rutter testified that the OUCC recommended adoption of the Updated Plan adjusted for the accounting errors corrected in NIPSCO's

November 19, 2014 filing and the recommendations of OUCC witnesses Smith and Grosskopf addressed below.

Rural Extension Projects

Mr. Shambo testified that while NIPSCO originally estimated $98.8 Million in rural extensions would be performed during the life of the 7-Year Gas Plan, with approximately $13.3 Million of those expenditures occurring in Year 1 of the Plan, NIPSCO now projects rural extensions of $217 Million over the life of the Plan with approximately $23 Million of those expenditures occurring in the first year. He testified that the primary reason for the increase is a substantial increase in the number of rural customers included in the Updated Plan. He noted that while rural extension cost projections in the 7-Year Gas Plan approved in Cause No. 44403 (the "Approved Plan") included only rural customers that would be converting from an alternative energy source, it became clear that it would be very difficult from a record keeping and project management standpoint to distinguish between rural projects undertaken under the 20-year margin test under Ind. Code § 8-1-39-11 and rural projects that are or could become eligible for extension under NIPSCO's existing line extension policy in Rule 6 of its General Rules and Regulations Applicable to Gas Service ("Rule 6") (a 6-year margin test). Mr. Shambo explained that NIPSCO wants to encourage development of new line extension projects in a logical way that is consistent with sound planning and operational practices, but that the difficulty in distinguishing which customers should be attributed to what project for purposes of investment tracking, cost recovery, and margin calculation posed the likelihood that the planning and operational advantages of an organized approach to these extensions could be lost under NIPSCO's original proposal.

Mr. Shambo admitted that NIPSCO simply underestimated the challenges associated with rural extensions, and as a consequence the resulting cost projection was low driven primarily by the number of customers NIPSCO now proposes to reach as a result of its revised rural extension approach. He testified that NIPSCO is including all rural customers in the Updated Plan because (a) the statute provides that extensions to rural areas are eligible for recovery and authorizes the use of up to a 20-year test and does not distinguish customers that might be eligible for connection under a lower threshold of eligibility, (b) NIPSCO's revised approach to rural extensions dramatically reduces complications associated with trying to track facilities added solely for the benefit of customers converting from other energy sources such as propane, and (c) it would be inequitable to provide incentives for some rural customers to convert to natural gas, while a new rural customer literally down the street could be required to pay a contribution in aid of construction to get gas service. He concluded that by providing a credit to the TDSIC tracker for margins associated with all new rural customers, the impact to existing customers is dramatically reduced. He stated that while such a significant change in investment level could be considered a "material" change in most cases, NIPSCO's proposal to credit back actual margins from new customers added under the rural extension projects effectively eliminates the impact on existing customers while new customers will continue to provide overall system benefits well beyond this 7 year period.

Mr. Shambo provided a comparison of extensions undertaken under the current Commission Rule (based on a comparison of three years of total revenue to the cost of the extension), Rule 6 (which employs a 6 year margin test) and NIPSCO's revised rural extension program incorporated into its Updated Plan. He explained that the combination of increasing cost to build, decreasing usage per household, low gas costs and NIPSCO's low distribution rates make it very difficult for new customers to pass the three year revenue test without a contribution as well as NIPSCO's current gas extension rule, given that an average NIPSCO residential gas customer pays approximately $672 per year.[4] That revenue would support approximately $2,000 of investment under the Commission's Rule, $1,800 ($300 per year) under Rule 6, and only about $1,500 based on current NIPSCO residential gas margin data. In comparison, he testified that the cost of a service line, meter loop and regulator, and meter installed to a typical existing home is approximately $2,500 and that a customer requiring anything more than a standard service would therefore struggle to qualify for extension of service without a contribution even before the cost of additional distribution mains is considered.

Mr. Small testified that projected costs for the Rural Gas Extensions included in the Approved Plan did not anticipate extensions made under Rule 6, extensions performed based on an evaluation using a 6-year margin test, and those projects were not originally included with the rural TDSIC extensions that incorporate a 20-year margin test. His testimony incorporated a table that documented the impact of NIPSCO's revised approach on the cost of Rural Gas Extensions incorporated into the Updated Plan, and he testified that Rule 6 connections included in the Updated Plan are projected rural new business connections that NIPSCO anticipates may have been eligible for connection under Rule 6. The specific characteristics of any specific customer included in that estimate cannot be known in advance, but they are eligible for incorporation into the TDSIC based on their rural location and that the increase in the projected cost of Rural Gas Extensions was driven by the inclusion of all rural customer gas extensions, not just the rural TDSIC extensions that incorporate a 20-year margin test.

Mr. Small testified the projected costs for the Rural Gas Extensions was developed by estimating costs for the 3 components of the projects, (1) Service lines, (2) Meter Loops and Regulators, and (3) Mains. Unit costs were synchronized with demand forecast volumes, and then inflated at 3% per year to reflect further growth. The Mains estimate was derived using currently known projects with assumptions about other forecasted projects. For example, NIPSCO assumed the same rate of commercial connection as experienced under Rule 6, a decrease in residential connection requests under Rule 6, and an increase in residential development activity as rural mains are built out. He explained that NIPSCO has observed that not all customers connect to new gas mains as soon as natural gas service is first made available, so the revised budget was developed based on the assumption that 30% of residential customers will elect to connect to a new gas main in the first year, another 20% in each of the following three years, and 5% in the fifth year, for a total connection rate of 95%. He testified that by the end of the fifth year of service, most customers who desire to connect to the system will have done so yielding an overall weighted average connection rate over twenty years of 88%. He observed that Service Line and Meter Loop and Regulator installation costs therefore tend to lag Main costs over time – a phenomenon was built into the projected costs. Mr. Small explained that commercial customer connection rates were not assumed to follow the same trend as residential customers, but were modeled as connecting the same year as new main was installed consistent with NIPSCO's historical experience. He also clarified that while meter costs were included in the evaluation of the project under the 20-Year test, the cost of meters is not included for recovery in the TDSIC.

[4] Calculated as margin plus approximate gas costs.

Mr. Small testified NIPSCO projects that 3,306 customers will be connected in 2014 as a result of the revised approach to Rural Gas Extensions as compared to the original estimate for 2014 of 2,600, and noted that NIPSCO currently estimates that more than 46,000 customers will be connected to NIPSCO's gas system as a result of the proposed rural extension program over the life of the Updated Plan. Mr. Small sponsored updated projected costs for Rural Gas Extensions by category (Mains, Meter Loops and Regulators, and Service Lines) along with the number of customers projected to be connected each year under the Updated Plan as Petitioner's Exhibit No. MGS-2 (Confidential). Mr. Small testified that rural extension projects included in the Updated Plan are projected to pass the 20 year test identified in Ind. Code § 8-1-39-11, meaning that under NIPSCO's revised approach a twenty year projection of margins associated with the projects compared to the cost to build them results in the projects being cost effective.

Mr. Small explained that based on customer inquiries and interest, a "polygon" is established to define the area to be served. A design is then prepared by NIPSCO's system planners for the facilities required to extend the distribution system and provide service within the polygon including routes, amounts of main by size, amounts of service line, regulator stations, etc. From that design, a cost of installation is estimated that is compared with the projected margins associated with customers expected to connect with the new project over a 20-year period, taking into consideration the factors such as connection rates and customer usage for both commercial and residential customers, that is then used to build a business case for the project in question.

Mr. Small incorporated a detailed example of the single largest rural extension project (known internally as "Project 18") into his testimony to document how the process works in a manner consistent with NIPSCO's effort to build out its system in a logical and efficient way from an operational standpoint, and sponsored an exhibit documenting the underlying analysis as Petitioner's Exhibit No. MGS-3 (Confidential). He testified that Project 18 entails the installation of more than 91 miles of mains and three regulator stations and is projected to serve more than 2,500 households and more than 300 businesses when installed and customer connection is complete. He noted that 2010 Census block data was used to identify prospective customers not inquiring for gas service but who might subsequently request service in the future in addition to the prospective customer inquiries. He explained that the total direct cost of completion of Project 18 is estimated to be $27.1 Million with margins estimated to be $33.2 Million over 20 years. He noted that the project was originally intended to be completed in three sequential phases, but that based on the desire to more rapidly extend service to more customers, the entire project would be completed by the end of 2015.

No evidence was presented challenging the accuracy of the cost projections proposed by NIPSCO in support of its revised approach to Rural Extension Projects in the Updated Plan. We find that nothing in the record supports the conclusion that the cost estimates associated with the Rural Extension Projects contained in the Updated Plan are not "best estimates" in the context of Ind. Code § 8-1-39-10(b)(1).

112th Street Project

With respect to the 112th Street Project, the Updated Plan includes project costs that have increased to more than $13 Million from the projection of $3.4 Million contained in the 7-Year

Gas Plan.[5] Ind. Code § 8-1-39-9-(f) provides that "[a]ctual capital expenditures and TDSIC costs that exceed the approved capital expenditures and TDSIC costs require specific justification by the public utility and specific approval by the commission before being authorized for recovery in customer rates."

Mr. Sangster provided an overview of the purpose and necessity of the 112th Street Project. He testified that at the end of 2014, one of the NGPL feeds to NIPSCO in the Whiting Indiana area will be retired due to pipeline integrity issues. He testified that the line is actually owned by Peoples Gas and is leased to NGPL for the sole purpose of providing a feed from the NGPL system to NIPSCO. Mr. Sangster explained that the 112th Street feed supports service to a number of large transportation customers as well as many residential customers and that NIPSCO is installing a feed from a regulator station on Standard Avenue in Whiting for three miles across the lake-front to tie in at the intersection of Indianapolis Boulevard and Calumet Avenue.

Mr. Sangster stated the 112th Street Project is still the highest priority project in the 7-Year Gas Plan. He stated this project is necessary for the continued gas service to NIPSCO customers in this area. The current delivery point is being retired at the end of 2014 and without this project there would be no way to continue to serve those customers.

Mr. Sangster testified there are no realistic alternatives to the completion of the 112th Street Project as designed. He stated the approach being taken is the safest, shortest and most cost effective path that NIPSCO found to be feasible and explained that the area in which the project had to be constructed in order to safely serve the NIPSCO customers is very congested with underground facilities. He noted that NIPSCO has an existing regulator station on Standard Avenue at the Whiting Clean Energy site that has capacity to feed the areas currently fed by NGPL's pipeline, making it an efficient and appropriate starting point and that to avoid as much underground congestion as possible, the project was engineered to turn the pipeline to the north, to the lake front where easements were purchased. The pipeline then goes west to the Horseshoe Casino at Calumet Avenue and turns south back to the tie in point at Indianapolis Boulevard.

Mr. Sangster testified the updated cost for the 112th Street Project is $13,348,839, an increase of $10,720,119. He stated that multiple factors have contributed to the increase in the projected cost, specifically:

- labor costs for the project came back significantly higher than estimated based on the actual bids received for the work;
- de-watering costs associated with the project were not included in the original project cost estimate;
- route changes required within the project drove unanticipated real estate (easement) acquisition expenses; and
- soil contamination has been encountered requiring environmental assessment and remediation that had not been anticipated at the time the original project cost estimate was prepared.

[5] NIPSCO's response to the Commission's December 4, 2014 Docket Entry projects the final cost of the 112th Street Project to be $14,164,070.

Mr. Sangster sponsored Petitioner's Exhibit No. KWS-1 documenting the impact of those factors on the overall cost of the 112th Street Project.

Mr. Sangster also explained the increase in labor costs in relation to the original estimate. He testified that when the original estimate for the 112th Street Project was prepared by EN Engineering, the assumed labor rate was estimated based on downtown Chicago labor rates based on the proximity of the project to Chicago. When actual bids for the work were received, the quoted labor costs were substantially higher than originally estimated. He noted that it is difficult to know the factors driving those bids, but testified that it is reasonable to assume that the combination of the known time sensitivity of the project and the complexity of the installation were contributing factors. Mr. Sangster testified that NIPSCO has little opportunity to mitigate that impact of the higher labor rates because the existing 112th Street NGPL feed will be taken out of service for integrity reasons at the end of 2014, and NIPSCO is therefore not in a position to take advantage of the customary commercial tools available to mitigate the impact such as deferring the project or re-bidding it in a different way.

Mr. Sangster testified NIPSCO investigated the possibility of using NIPSCO crews for the completion of the 112th Street Project, but that NIPSCO crews are not generally equipped to run over 3 miles of steel transmission pipeline nor does NIPSCO maintain manpower levels necessary to support a large capital project of this nature. He explained that NIPSCO crews are utilized for emergency response and smaller capital work such as installation of plastic distribution pipe, and that the use of outside resources that specialize in large scale steel gas main projects of this type is more cost effective.

Mr. Sangster explained the need for de-watering for the 112th Street Project. He stated that because of the proximity of the project to Lake Michigan and the low elevation associated with the project, excavation trenches are prone to flooding. To mitigate this condition, pumps must be deployed to remove water from subsurface excavations to allow work to proceed. Mr. Sangster stated the estimated incremental cost of de-watering associated with the 112th Street Project is $1,250,000. He also explained that the original project estimate did not anticipate the need to acquire additional easements outside of public rights-of-way to accommodate the new facilities. To complete the project, the final engineering design and routing required acquisition of additional easements (primarily from the City of Whiting) at a cost of $1,637,074.

OUCC Witness Smith provided testimony critical of the Updated Plan estimate of $13,348,839 for the 112th Street Project. She noted that over the course of just one year, the project has an increased cost of four times the original cost estimate approved by the Commission. Ms. Smith stated that the timeline shows that NIPSCO knew with absolute certainty on June 17, 2013 that the NGPL line would be retired December 2014, yet NIPSCO waited from June 2013 until the end of April 2014 before soliciting bids. Part of the delay was also occasioned by NIPSCO re-routing the project submitted in the Plan (June 2013 – March 2014). Ms. Smith testified that if in October 2013 NIPSCO had submitted a revised best estimate, bids could have been submitted earlier and it is probable the labor impact could have been reduced.

Ms. Smith stated the OUCC was alarmed that NIPSCO did not reveal the original route was unreasonable until after the Commission determined the estimate "best", and expressed concern that NIPSCO is now calling the Plan estimate for this highest priority project "analogous," while in Cause No. 44403 NIPSCO referred to that project as having the "best estimate," containing considerable detail and having a +/- 20% accuracy level. Ms. Smith testified the OUCC wants any project performed in a safe manner and that the OUCC's frustration lies in NIPSCO's lack of attention to the project's routing until after NIPSCO received Commission approval for the project and its associated $3,322,780 cost.

Mr. Phillips was also critical of the updated costs for the 112th Street Project, and contended that the ability to track costs for the project had not resulted in the promised cost effectiveness or enhanced budgetary and planning certainty NIPSCO identified in its electric TDSIC tracker proceeding in Cause No. 44371. He recommended that NIPSCO not be permitted to recover costs for the 112th Street Project in excess of its original estimate.

Mr. Small responded to the assertions that NIPSCO was not expeditious in seeking bids for the work associated with the 112th Street Project resulting in a substantial increase in project costs and described the specific steps taken in developing the 112th Street Project through early 2014. He indicated that initial parameters for a potential alternative to the 112th Street feed from NGPL were developed in January of 2013. He explained that NIPSCO had been informally discussing concerns about the integrity of the feed to 112th Street for some time, and that the request was made to EN Engineering for preparation of a feasibility study to proactively identify potential solutions given the uncertainty surrounding the long-term availability of the NGPL line.

Mr. Small explained that the feasibility study was requested prior to passage of the TDSIC Statute and that NIPSCO specified no specific route, as the focus was on the operational requirements of the project such as the pressure requirements, minimum pipe diameter and the tie-in and endpoints for the line. He testified that EN Engineering provided a feasibility study for the 112th Street relocation project on February 20, 2013 that evaluated two alternative routes, one running along Indianapolis Boulevard and a second lakefront route running along Lake Michigan through Whiting. Mr. Small explained that the feasibility study was completed as a Class 3 estimate consistent with the AACE International standard incorporated into its recommended best practices and clarified that Class 3 estimates of the type provided by EN Engineering are appropriate for use in budget authorization and control with an expected accuracy range for -20% to +30%, and are estimated using semi-detailed unit costs and assembly level line items. Mr. Small noted that the cost estimates associated with the feasibility study specifically excluded easement costs and costs associated with environmental remediation such as the removal of contaminated soils.

Mr. Small testified that a decision was made in March of 2013 that the 112th Street Project should be routed using the lakefront route because the routing of a high pressure main through an urban area was unacceptable from a safety standpoint, but that the precise route for the project was not determined until much later because of required engineering, facility siting, and land availability investigation. He added that at that time, NIPSCO was still pursuing discussions with NGPL on other alternatives for the 112th Street station and the decision to decommission the line feeding the station had not been made by NGPL. While formal notification was not provided to NIPSCO until July 17, 2013, Mr. Small testified that NIPSCO was informed in April of 2013 of the likelihood that the NGPL line would be decommissioned.

Mr. Small explained that NIPSCO released EN Engineering to prepare the detailed engineering for the project in early June of 2013, including preparation of design drawings and project specifications. He testified that the primary hurdle for designation of a final route was the siting of the regulator station required for the project because (a) it dictated the route for some of the project, and (b) it impacted some of the design parameters of the project, but that much of the majority of the design drawings and project specifications could begin prior to that siting decision. Mr. Small provided a detailed discussion of the time consuming process required to ultimately site the regulator station and testified that the specific route for the project had not been finalized until after Cause No. 44403 had been heard.

Mr. Sangster submitted rebuttal testimony to explain the RFP process used by NIPSCO for designing and bidding large projects including the 112th Street Project, and provide additional detail about the increased costs for the project and steps NIPSCO has taken and will take to improve upon its ability to accurately estimate costs for major projects. He explained that in an effort to optimize NIPSCO's ability to execute large gas and electric projects the Major Projects Group was assigned responsibility over the larger TDSIC projects like the 112th Street Project in March of 2014 immediately prior to the final design and property acquisition activities and the issuance of the RFP.

Mr. Sangster explained that completion of the siting of the regulatory station was among the first areas of focus for Major Projects, and that the site was identified and negotiation with the landowner for purchase of the property initiated so that the route for the project was finalized in March of 2014. Mr. Sangster stated that land acquisitions began in March of 2014 and that acquisition of easements and property rights was concluded in April of 2014. He explained that NIPSCO had already spent approximately $269,000 on the 112th Street Project prior to the Commission's approval of its Order in Cause No. 44403, and that on April 30, 2014 NIPSCO issued an RFP seeking fixed cost firm bids for completion of the 112th Street Project. He stated the contract was awarded on July 31, 2014 and work began on June 27, 2014 based on the issuance of a Limited Notice to Proceed to the contractor.

Mr. Sangster provided a detailed explanation of NIPSCO's process for development, issuance, and response to RFPs for major construction projects, testifying that RFPs are developed when engineering is completed to an extent sufficient to solicit firm price bids from contractors. He noted that RFPs issued before the engineering work has been sufficiently completed result in bids that contain substantial amounts of contingency to mitigate risk to the contractor, and also frequently require more numerous change orders to accommodate unforeseen work. He said NIPSCO typically gives bidders 2 to 6 weeks to generate bid proposals, depending on the complexity of the work scope and that expiration of pricing associated with bids is set by the bidders, but typically NIPSCO would normally have 30 days to accept or reject the bid proposal, subject to modification based on contractual issues associated with final negotiations.

Mr. Sangster testified that NIPSCO followed that RFP process for the 112th Street Project and provided the following timeline for the RFP issued for the 112th Street Project:

March 25, 2014	RFP Development Started
April 30, 2014	RFP Issued
May 23, 2014	Bids Returned
June 27, 2014	Limited Notice to Proceed Issued to Contractor
July 31, 2014	Purchase Order Issued, Contract Awarded

Mr. Sangster testified the RFP sought fixed price bids for the completion of the 112^{th} Street Project according to NIPSCO's specifications with a specified completion date of December 2014 because this allowed for accurate scoping and competitive pricing without undue levels of risk contingency due to incomplete engineering designs. In contrast, he testified that time and material arrangements for a project of this nature and complexity would not have been used regardless of the timeframe of the RFP because of the risk of exposure by NIPSCO (and its customers) to the potential for unnecessary cost escalation as field conditions were encountered. In the case of the 112^{th} Street Project, he explained that NIPSCO was sensitive to the need to complete the work by a time certain, and also recognized that part of the project route along the lake would likely involve complications associated with other underground facilities due to the brownfield nature of some of the property.

Mr. Sangster testified the bids received were substantially higher than the projections made by EN Engineering. He stated the biggest contributing factor to the increase was an increase in labor costs from $1,035,000 to $6,425,635 in comparison to the original labor estimate of $1,035,000.

Mr. Sangster testified that NIPSCO has further investigated the source of the labor cost variance since the filing of its case-in-chief and it appears in retrospect that EN Engineering underestimated the complexity of a portion of the project along the lakefront route. He explained that EN Engineering assumed a conservative and reasonable Chicago hourly labor rate for the project, but likely underestimated the labor hours required in part by assuming that much of the installation could be accomplished using directional boring technology rather than open trenching the lines. He added that directional boring is less labor intensive than open trench installation, but is not feasible in areas with substantial amounts of existing underground facilities. He explained that industrial brownfield areas have extensive amounts of underground facilities which cannot be effectively located without being completely exposed, leading to a very time consuming and tedious process requiring use of vacuum and hydro-vacuum excavation to expose facilities, followed by coordination with landowners to identify the nature of the facilities encountered.[6] He testified that the bids NIPSCO received likely reflected a better understanding of the specific area than did the original estimate.

Mr. Sangster testified NIPSCO did not recognize that the EN Engineering estimate may have understated labor costs because NIPSCO relied heavily on EN Engineering for the development of estimates because NIPSCO had not had experience with large transmission pipe projects such as the 112^{th} Street Project in recent years. He explained that NIPSCO is developing additional project estimation capabilities in-house to improve the ability to more accurately estimate complex gas construction project costs in the future.

Mr. Sangster provided details relating to the other contributing factors for why the bids received were substantially higher than the original projections including the basis for increases in Other Construction Contract Costs, engineering and inspection costs, Land Costs, and de-watering. He explained that de-watering was not included in the specifications for the 112th Street Project and the error was not discovered until the detailed engineering was completed. He

[6] Operators of industrial facilities are not subject to the provisions of Ind. Code Ch. 8-1-26, so "Call Before You Dig" locators do not and cannot identify those facilities.

explained that de-watering was required for portions of the final route based on the proximity of the project to Lake Michigan and the low elevation. The original estimate did not contemplate de-watering. He explained that while the majority of the facilities associated with the 112th Street Project have been installed in public rights-of-way, easements (primarily from the City of Whiting) to complete the project were significantly more expensive than originally anticipated.

Mr. Sangster disagreed with Ms. Smith that NIPSCO understood that the cost of the 112th Street Project had changed prior to the conclusion of the Cause No. 44403 proceeding. He stated that components of project estimates are always higher or lower than initially projected, but the first understanding NIPSCO had that the overall cost of the project would significantly exceed the amount projected by EN Engineering was when the bids were received on May 23, 2014. The record in Cause No. 44403 closed on February 18, 2014.

Mr. Sangster disagreed with Ms. Smith and Mr. Phillips that the earlier issuance of an RFP might have reduced the cost of the 112th Street Project. He stated that the bids received in May of 2014 were significantly higher than NIPSCO's original estimate, but there is no reason to believe that those bids would have been significantly different had the RFP been issued earlier. He stated that the underestimation of the complexity of a portion of the project along the lakefront route would not have been remedied by issuing the bids earlier. He expressed confidence in the accuracy of other estimates provided by EN Engineering and that based on the results of other gas TDSIC projects that are currently underway it appears that EN Engineering's estimates have been reasonable in light of actual experience to date. In addition, NIPSCO has asked EN Engineering to re-evaluate its cost estimates for other projects in light of the result of the 112th Street Project, and that they have continued to express confidence in their original cost projections.

Subsequent to the hearing held in this Cause, the OUCC and NIPSCO submitted a Joint Proposed Order on this issue, which provided that the OUCC and NIPSCO agreed that NIPSCO should not collect a portion of the increased cost of the 112th Street project in its TDSIC tracker, but rather NIPSCO had agreed, beginning in TDSIC-2, to defer 75% of all TDSIC costs incurred related to this project (approximately 20% of the overall revised estimate plus a portion of the incremental costs discussed above) including depreciation, pretax returns, AFUDC, post in service carrying costs, O&M and property taxes to be recovered in NIPSCO's next general rate case.

In deciding whether the OUCC and NIPSCO's proposed resolution is reasonable, the Commission would note the primary issue raised by Ms. Smith was whether NIPSCO should have recognized flaws in the original estimate in time to update the estimate provided in Cause No. 44403 or positively impact the pricing received by bidding the job sooner. We find Mr. Small and Mr. Sangster's rebuttal testimony and responses given at the hearing about the logistical challenges of the 112th Street Project and the attendant impact on the timeframe of the RFP for the project to be instructive as to the complexity and fluidity of the project from an operational execution standpoint, including significant detail on the progression of the project that convinces us that, while regrettable, the cost escalation associated with the 112th Street Project was not avoidable given the urgency of the project and the steps necessary to design and bid the work.

While we find that the increased cost of the 112th Street Project is justified, the Commission is concerned about the nature and effectiveness of NIPSCO's communication of changes in the project to its stakeholders both through the informal process we required in Cause No. 44403 and after the initiation of this proceeding. We are cognizant that operational conditions can and do change especially with time-sensitive projects, as the record here demonstrates. However, the significant cost and short procedural timeframe associated with filings under Ind. Code ch. 8-1-39 mandate that information be shared on a cooperative basis to the maximum extent possible to ensure that participating parties and the Commission are able to effectively evaluate and address the extent to which TDSIC planning and execution remain aligned. Mr. Sangster's rebuttal testimony explained NIPSCO's desire to improve internal project estimation and management processes and the existence of a process to produce such improvements. We understand that substantial capital projects involve elements of risk with respect to scope and cost as they progress, but we strongly encourage (a) the development of improved estimation techniques and project management practices that will reduce the likelihood of significant changes such as those experienced with the 112th Street Project in the future, and (b) adoption of improved internal and external communication protocols to mitigate the likelihood that the circumstances present with NIPSCO's 112th Street Project recur in subsequent filings. Given the totality of the unique facts in this case, we find that the OUCC and NIPSCO's proposal is a unique resolution to a difficult situation, and is an acceptable outcome.

Bare Steel Projects

Mr. Small testified that although NIPSCO anticipates an approximately $8.5 Million increase in the cost of bare steel projects in the Updated Plan no changes are anticipated for the 2014 Projects. He explained that the original assumptions about bare steel replacement included a belief that NIPSCO would be able to replace existing bare steel mains with only 80% of the existing mileage, with the rest being engineered out through redesign. He testified that additional design engineering performed now leads to the understanding that a mile for mile replacement assumption is more accurate. He noted that NIPSCO has determined that a majority of the miles requiring replacement are in the downtown Gary area, and will require replacement of pipe in a heavily urban setting including replacement of a significant amount of larger pipe than originally projected. He added that the System Data Integrity Program included in the Updated Plan will give NIPSCO a more complete understanding of remaining bare steel pipe and that the overall bare steel project will be monitored and reconciled with new records knowledge and any additional plan adjustments made as warranted.

Barbara A. Smith presented the OUCC's recommendations regarding NIPSCO's bare steel and 112th Street projects as well as the OUCC's review of other project changes. Ms. Smith testified although NIPSCO did not submit any testimony on the additional design engineering around bare steel, the OUCC discussed this lack of design engineering with NIPSCO during several technical meetings and conducted discovery on the issue. The OUCC recommends the Commission deny NIPSCO's requested $8.5 million bare steel budget enlargement at this time. She recommended that NIPSCO resubmit its proposal in its fall 2016 or 2017 TDSIC tracker filing because (1) the amount of bare steel existing and needing replaced is not currently known and will not be known until the end of 2016 when the linen project is complete, and (2) NIPSCO's proposed increase in bare steel capital spend is not scheduled to begin until 2018. Ms. Smith testified that if the Commission were to approve that portion of NIPSCO's Updated Plan, ratepayers may be harmed by the precedent that would be set by authorizing undefined project dollars that could ultimately be transferred to other projects within the Plan should cost projections prove inaccurate. She stated NIPSCO would not be harmed in waiting until at least 2016 for this increase when the project is properly defined.

Ms. Smith testified it appears the TDSIC Statute's requirements for such an expansion are not met. She stated that without specific information as to the location as well as scope of the proposed additional replacements, the statutory requirements cannot be satisfied. She stated the Commission should not expand a 7-year plan budget without justification, and NIPSCO has not supplied such justification. Ms. Smith expressed concern that NIPSCO did not conduct a proper level of bare steel project assessment for either the original Plan or the Updated Plan. She stated that after expressing its concern to NIPSCO, the OUCC understands that going forward NIPSCO has a process to better incorporate local operations knowledge and specific asset health information into its revised risk modeling. She stated the OUCC will monitor future TDSIC tracker filings to ensure local operations data is incorporated into NIPSCO's TDSIC risk and prioritization model. Ms. Smith stated this new process does not change the fact that NIPSCO's proposal to increase the Plan budget by $8.5 million is inappropriate at this time, such process only underscores that NIPSCO does not know its ultimate bare steel replacement mileage or needed budget.

We note that our approval of the categories of projects in Cause No. 44403 was presumptive, but premised on submission of detailed estimates for work in the upcoming year in subsequent TDSIC filings. 44403 Order at 24. The evidence shows the bare steel projects for which the increased costs were identified are not scheduled to occur until 2016 and beyond and the updated cost estimates for the 2016 – 2020 bare steel projects are not detailed cost estimates, Although we appreciate that NIPSCO provided updated information regarding the bare steel projects for years 2016-2020 for informational purposes and to keep us abreast of the information NIPSCO knows at this time, we find that the updated estimates for bare steel projects in the Updated Plan do not provide the best estimate of the cost of those projects and we do not believe the updated cost estimates for the bare steel projects should be included in the Updated 7-Year Plan that we approve herein. We would expect NIPSCO to include projected increases and decreases for the bare steel projects TDSIC filings consistent with its obligation to provide best estimates under the Statute and in the interest of promoting transparency consistent with the informal stakeholder process identified in the 44403 Order.

Based on our review of the evidence we find that NIPSCO has provided sufficient support for the estimate of the cost of the eligible improvements included in the Updated Plan with the exception of the updated cost estimates for the bare steel projects for years 2016 – 2020 which we find should not be approved as part of the Updated 7-Year Plan that we approve herein. The evidence shows the cost estimates for the investments included in the Updated 7-Year Gas Plan (with the exception of the updated cost estimates for the bare steel projects for years 2016 – 2020 which we find should not be approved as part of the Updated 7-Year Plan that we approve herein) were based on NIPSCO's experiences for similar work. Finally, NIPSCO incorporated actual costs incurred into its revised estimates for the Year 1 projects. Therefore, consistent with our findings in Cause No. 44403 relating to the approved 7-Year Gas Plan, and based upon the evidence presented in this proceeding, we find that the Updated Plan (with the exception of the updated cost estimates for the bare steel projects for years 2016 – 2020 which we find should not be approved as part of the Updated 7-Year Plan that we approve herein) includes the best estimate of the cost of the eligible improvements included in the Plan.

(2) Public Convenience and Necessity.

Ind. Code § 8-1-39-10(b)(2) requires that an order approving a utility's 7-Year Plan include a determination whether public convenience and necessity require or will require the eligible improvements included in the plan. In undertaking this review, we are mindful that 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. Small testified that consistent with the Approved Plan, the eligible improvements included in the Updated Plan will serve the public convenience and necessity. Mr. Small explained that NIPSCO's Updated Plan follows the requirements of the Statute by making investments for the purposes of safety, reliability, system modernization and economic development consistent with public policy and the public interest. No evidence was presented in this Cause to contest the public convenience and necessity associated with the Updated Plan.

NIPSCO has a statutory obligation to provide adequate retail service in its certificated gas service territory pursuant to Ind. Code § 8-1-2.3-4(a). It performs this obligation for the public convenience and necessity. We find that NIPSCO has sufficiently supported that the investments described in its Updated Plan are reasonably necessary for it to continue to provide adequate retail service to its customers. Therefore, consistent with our findings in Cause No. 44403 relating to the Approved Plan, and 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 Updated Plan.

(3) Incremental Benefits Attributable to the 7-Year Gas Plan.

Ind. Code § 8-1-39-10(b)(3) requires that an order approving a utility's 7-Year Plan include a determination whether the estimated costs of the eligible improvements included in the plan are justified by the incremental benefits attributable to the plan.

Mr. Small testified that like the Approved Plan, the Updated Plan is intended to provide benefits in the form of investments to maintain and improve system reliability through the capacity of the system to deliver gas to customers when they need it, replacement of certain system assets to ensure the ongoing integrity and safe operation of the gas system, investment in data and technology required for the gas system integrity program, and the extension of gas facilities into rural areas. With respect to rural extensions in particular, he explained that the Updated Plan is projected to increase the number of rural customers served over the life of the plan to more than 46,000.

In the 44403 Order, we found that "NIPSCO's 7-Year Gas Plan contains solutions that will enhance customer and employee safety, avoid outages, preserve operational integrity, provide equipment protection, and meet evolving customer demands." 44403 Order at 23. Based on our review of the evidence, the facts underlying that conclusion have not changed. Therefore, consistent with our findings in Cause No. 44403 relating to the Approved Plan, and based upon the evidence presented in this proceeding, we find the estimated costs of the eligible improvements included in the Updated Plan are justified by the incremental benefits attributable to the Updated Plan.

(4) Whether NIPSCO's Updated Plan is Reasonable.

Ind. Code § 8-1-39-10 provides: "If 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 TDSIC treatment."

We have already concluded that the Updated Plan includes the best estimate of the cost of the eligible improvements included in the Updated Plan, excluding the projected increased cost for bare steel, the public convenience and necessity require or will require the eligible improvements included in the Updated Plan, and the estimated costs of the eligible improvements included in the Updated Plan are justified by the incremental benefits attributable to the Updated Plan. These three factors are the essential ingredients of reasonableness within the context of the TDSIC Statute; having found the best estimate of costs, that the public convenience and necessity requires or will require the improvements in the Plan, and that the costs are justified by the benefits, we would be hard pressed to conclude that the Updated Plan is anything other than reasonable. In Cause No. 44403, we found that "NIPSCO's 7-Year Gas Plan appropriately and reasonably addresses NIPSCO's aging infrastructure through projects intended to enhance, improve and replace system assets for the provision of safe and reliable natural gas service, as well as the cost-effective extension of service into rural areas." 44403 Order at 23. Nothing in the evidentiary record here leads us to a different conclusion. Further, the evidence demonstrates that the Updated Plan does not contain any "material changes" that would require the creation of a sub-docket. The Updated Plan contains updates of cost estimates for Year 1, a detailed project list and cost estimates for Year 2, and a revised risk ranking of NIPSCO's projects. We note that while the cost of NIPSCO's Rural Extension Projects increased substantially over the estimate provided in support of its Approved Plan, the overall impact of those projects is reduced by virtue of NIPSCO's proposal to credit 80% of the margins associated with customers served by those projects.

In conclusion, consistent with our findings in Cause No. 44403 and based on the findings set forth herein, we find the Updated Plan to be reasonable.

(5) Conclusion.

With the exception of the proposed increase for bare steel in years 2016-2020, we find that the uncontested evidence of record supports the conclusion that the projects identified in the Updated Plan are "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code §§ 8-1-39-2 and 10(a). The project categories contained in Years 2016-2020 are presumed "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code § 8-1-39-2, subject to further definition and specifics being provided through the plan update proceedings as set forth in the 44403 Order. The evidence shows that all assets included in the Updated Plan are categorized as gas transmission, distribution, or storage assets by the FERC Uniform System of Accounts and have been undertaken for purposes of safety, reliability, system modernization, or economic development. No party presented any evidence that suggests that the assets included in the Updated Plan are not properly identified as transmission and distribution improvements, or that suggests that the proposed improvements are not being undertaken for purposes of safety, reliability, system modernization, or economic development. While questions were raised about the ratemaking treatment to be afforded some costs associated with some specific projects, no party contested the eligibility of the projects identified in the Updated Plan for TDSIC treatment. Therefore, in accordance with Ind. Code § 8-1-39-10, we find the Updated Plan to be reasonable, and we hereby designate the eligible transmission, distribution, and storage improvements included in the Updated Plan as eligible for the TDSIC treatment.

b. <u>Findings and Conclusions Regarding Proposed TDSIC Mechanism</u>.

In accordance with Ind. Code § 8-1-39-9(a), NIPSCO is seeking authority to implement a semi-annual adjustment mechanism through which NIPSCO will seek to recover 80 % of eligible TDSIC costs associated with approved TDSIC projects as defined by Ind. Code § 8-1-39-2. Our review first addresses the proposed ratemaking treatment to be afforded approved TDSIC projects, then addresses the remaining issues associated with the calculation of Petitioner's proposed TDSIC factors.

(1) <u>Ratemaking Treatment and Calculation of TDSIC Adjustment and Deferral Under Ind. Code §§ 8-1-39-9(a) and 9(b)</u>.

Under Ind. Code § 8-1-39-9(a), "a public utility that provides electric or gas utility service may file with the commission rate schedules establishing a TDSIC that will allow the periodic automatic adjustment of the public utility's basic rates and charges to provide for timely recovery of eighty percent (80%) of approved capital expenditures and TDSIC costs." The remaining 20% of approved capital expenditures and TDSIC costs may be deferred for future recovery under provisions of Ind. Code § 8-1-39-9(b), which provides that:

> A public utility that recovers capital expenditures and TDSIC costs under subsection (a) shall defer the remaining twenty percent (20%) of approved capital expenditures and TDSIC costs, including depreciation, allowance for funds used during construction, and post in service carrying costs, and shall recover those capital expenditures and TDSIC costs as part of the next general rate case that the public utility files with the commission.

Section 9 of the Statute thus provides that 80% of eligible TDSIC expenses may be recovered through a semi-annual tracking adjustment, and the remaining 20% deferred for recovery in the utility's next general rate case.

NIPSCO presented extensive and detailed evidence concerning its proposed TDSIC adjustment mechanism as discussed above. As discussed by NIPSCO witness Isensee, NIPSCO's proposed gas TDSIC mechanism strongly correlates with the mechanism approved by the Commission in Cause No. 44371 for NIPSCO's electric TDSIC. With three exceptions, no party offered evidence that contested the ratemaking methodology proposed by NIPSCO for the calculation of either the statutory TDSIC adjustment or the amount to be deferred for future recovery. The three contested issues were (a) the return on equity component of the calculation of pretax return under Ind. Code §§ 8-1-39-3 and 8-1-39-13, (b) the OUCC's proposed allocation of distribution related TDSIC costs among customer classes, and (c) the OUCC's proposal to require deferral of 20% of actual margins associated with rural extension projects undertaken as part of its 7-Year Gas Plan. Each is each addressed separately below.

(a) Calculation of Pretax Return.

Ind. Code § 8-1-39-13(a) sets out the factors the Commission may consider in determining the appropriate pretax return for purposes of calculating TDSIC costs:

> (1) The current state and federal income tax rates.
> (2) The public utility's capital structure.
> (3) The actual cost rates for the public utility's long term debt and preferred stock.
> (4) The public utility's cost of common equity determined by the commission in the public utility's most recent general rate proceeding.
> (5) Other information that the commission determines is necessary.

Mr. Isensee testified that, as required by Ind. Code § 8-1-39-3, NIPSCO will calculate the pretax return using its weighted average cost of capital ("WACC") consistent with the methodology approved by the Commission for NIPSCO's 7-Year Electric TDSIC Tracker and as used for other capital trackers such as NIPSCO's electric ECR. Mr. Isensee presented this calculation in Exhibit 2, Schedule 1. NIPSCO proposes to use 9.9% as the return on equity in the calculation of the pretax return for use in the TDSIC as approved in NIPSCO's most recent gas general rate proceeding.

Industrial Group witness Phillips contended that the 5.49% fair value return from the *Stipulation and Settlement Agreement* in NIPSCO's 2010 rate case should be used as the basis for the calculation of pretax return associated with NIPSCO's Gas TDSIC investments. We disagree. First, as NIPSCO witness Shambo correctly explained in his rebuttal testimony, a return on equity of 9.9% was agreed upon by the parties in Cause No. 43894 and was then adjusted downward by an inflation factor to reach an agreed upon fair return. Inflation is intended to measure change in price over time, and is not appropriate for consideration of value at the date of a TDSIC investment. Indeed Industrial Group witness Phillips acknowledged that at the time of installation, the original cost and fair value of capital assets is the same, but he incorrectly concluded that those values intersect at a lower inflation-adjusted rate rather than at the actual cost of installation reflected by NIPSCO's current WACC that incorporates a 9.9% return on equity. Second, during cross-examination, Mr. Phillips agreed that the Commission's 2013 Rate Order provided for the use of a 9.9% cost of equity in cases filed under Ind. Code ch. 8-1-39 and that a 7.0% return on equity is not mentioned anywhere in that Order. It is clear from the evidence of record that all parties to that agreement were aware of NIPSCO's plan to seek relief under the TDSIC Statute. *See NIPSCO Exhibits CX-2 and CX-3.*

Based on the evidence of record, we find that NIPSCO's proposed use of its WACC in a manner consistent with its ECR mechanism and our Order in Cause No. 44371 is consistent with the provisions of Ind. Code § 8-1-39-13 and should be approved, including NIPSCO's proposed use of 9.9% as the return on equity component of that calculation.

(b) Allocation of TDSIC Distribution Costs.

Mr. Shambo testified that consistent with the Commission's Order in Cause No. 44371, NIPSCO is proposing that the cost of transmission system improvements be allocated among all customer classes consistent with the revenue allocation from Cause No. 43894, while distribution system improvement costs would not be allocated to transportation customers receiving service under Rates 428 and 438. He testified the costs associated with storage projects would be allocated in the same manner as distribution costs, and the cost of rural extension projects would be allocated in the same manner as transmission and distribution costs, based on the character of the facilities installed.

OUCC witness Grosskopf testified that TDSIC costs associated with distribution system projects should be allocated to both distribution and transportation customers using the same percentages proposed by NIPSCO for transmission projects. Mr. Grosskopf contended that the cost of service study prepared by NIPSCO in Cause No. 43894 proposed allocation of distribution costs to transportation customers supported his proposal because the Settlement Agreement in that case did not specifically exclude an allocation of distribution costs to transportation customers.

In his rebuttal testimony, Mr. Shambo testified that the rates approved in Cause No. 43894 were based on percentage reductions from the then effective rates, not on a cost of service study. Mr. Shambo added that NIPSCO's proposal is consistent with the approach approved by the Commission in NIPSCO's electric TDSIC filing in Cause No. 44371 in that exclusion of transportation customers from an allocation of gas TDSIC distribution costs here is analogous to the exclusion of customers in NIPSCO's electric Rates 632, 633, and 634 from an allocation of electric TDSIC distribution costs, and that cost causation and cost allocation are thereby aligned. In his cross-answering testimony, Industrial Group witness Phillips testified that the cost of service study sponsored by NIPSCO witness Ronald Amen was inappropriate for the identification of class revenue allocations in this case because that study was neither used nor approved for establishing rates in Cause No. 43894. He also noted that the agreement approved by the Commission in that cause was based on an agreed fair value rate base that was different than the basis used by Mr. Amen in his study.

Based on our review of the evidence, we find that NIPSCO's proposal that the revenue allocation factor be adjusted for transportation Rates 428 and 438 is consistent with Ind. Code § 8-1-39-9(a)(1) and should be approved. NIPSCO's proposal to exclude Rates 428 and 438 from an allocation of distribution costs associated with its TDSIC investments is a reasonable method to accomplish the alignment of the cost causation with cost allocation, under the evidence specific conditions presented in this proceeding together with the 2010 Rate Order, for the purpose of allocating distribution costs in a manner that comports with Ind. Code § 8-1-39-9(a)(1). We find it is appropriate to adjust the allocation factors approved in the 2010 Rate Order by removing Rates 428 and 438 from the calculation for purposes of allocating distribution related TDSIC costs so that rate classes that do not use the distribution system are not allocated distribution costs. The cost of service study filed by NIPSCO in Cause No. 43984 cited by OUCC witness Grosskopf was not used in the development of the approved rates in that proceeding, as correctly noted by witnesses Shambo and Phillips, and thus is irrelevant to our examination here. Based on the evidence, we find that the OUCC's proposal to allocate TDSIC costs associated with distribution projects to transportation customers receiving service under Rates 428 and 438 should be rejected.

(c) <u>Deferral of Rural Extension Margins.</u>

Mr. Shambo stated that NIPSCO is proposing to credit 80% of actual margins associated with new customers connected through the rural extension program, consistent with the TDSIC percentage tracked recovery on investments. He testified that NIPSCO now projects total rural extension investments of $217.7 million (an increase of $118.9 over the Approved Plan), and estimates that these investments will result in $72.7 million in charges to customers through the TDSIC tracker over the 7-year plan. NIPSCO's proposed 80% credit of margin from new rural customers is estimated to be $67.0 million for the same period resulting in a net impact to existing customers of only $5.7 million over the 7-year plan – a substantial reduction in recovery relative to the Approved Plan.

Mr. Grosskopf disagreed with NIPSCO's proposal to limit margin credits to 80% of total margin revenue. He stated that capturing 20% of test year rural extension revenue in the next rate case ignores the fact that the utility received and retained 20% of the margin revenue in each of the preceding years. He stated margin revenue needs to offset TDSIC revenue completely, not by only 80% as requested, and that the 20% margin revenue received each year should offset the TDSIC revenue deferred each year. The 20% margin revenue from rural extensions should be deferred until the next base rate case, and matched as a credit to the TDSIC revenue deferred over the same period, for net revenue recovery in the next rate case. He opined that the utility will receive full revenue recovery for its investments, and the ratepayers' rate increase will be mitigated to what is fair and equitable in the next rate case.

Mr. Phillips testified NIPSCO's proposal to provide a credit for new margin should be expanded to include increased sales and margins from the level used to design rates in the last base rate case, from each rate class.

In rebuttal, Mr. Shambo addressed the OUCC's recommendation that NIPSCO be required to defer margins over and above the 80% that NIPSCO proposes as a credit to its TDSIC factor as an offset against the 20% of TDSIC expenses deferred for future rate case recovery. He testified that NIPSCO proposed to voluntarily credit the TDSIC tracker with 80% of the actual margins received from customers receiving service from rural extension projects constructed under NIPSCO's 7-Year Gas Plan as a means to help mitigate the impact of the projects on customers, but was under no obligation to do so as credits are not required. He explained that all appropriate revenues and expenses will be captured in the test period used to set new rates at the time of NIPSCO's next general rate case.

We find the proposals by the OUCC and the Industrial Group to be inconsistent with the provisions of Ind. Code § 8-1-39-11. The Indiana General Assembly crafted a statutory scheme that provides for a required balancing of current TDSIC recovery (80%) and cost deferral (20%), but does not require any offset for margins. The fact that NIPSCO has chosen to voluntarily incorporate a credit for 80% of actual revenues associated with its Rural Extension Projects to partially offset the cost of those extensions does not provide the Commission with authority to require more. As Mr. Shambo correctly noted at the evidentiary hearing, the *Stipulation and Settlement Agreement* approved in the 2013 Rate Order provides any party with an opportunity to seek review of NIPSCO base rates for gas service in November of 2017 – an opportunity to address the concerns raised by Mr. Grosskopf about the impact of margins associated with rural extensions in addition to the balance between TDSIC recovery and deferral prescribed in the Statute.

The evidence of record and the language of Ind. Code § 8-1-39-11 do not support the OUCC's proposal to require the deferral of 20% of actual margins associated with the Rural

Extension Projects nor does it support Mr. Phillips' proposal, and we accordingly conclude that the proposals should be rejected, and NIPSCO's voluntary credit of 80% of the actual margins received from new customers receiving service from rural extension projects should be approved.

(2) Findings and Conclusions Regarding Proposed TDSIC-1 Factors.

Having addressed the merits of the methodology to be employed by Petitioner in the calculation and implementation of its proposed TDSIC rate schedule, we now address the merits of the proposed factor for Petitioner's initial TDSIC-1 factor proposed to be effective for the billing months of February through May, 2015. We first address whether NIPSCO's petition in this Cause meets the requirements set forth in Section 9(a)(1) through 9(a)(3), then address the remaining calculations supporting the proposed factor.

Ind. Code § 8-1-39(a) provides in relevant part that the petition must:

> (1) use the customer class revenue allocation factor based on firm load approved in the public utility's most recent retail base rate case order;
>
> (2) include the public utility's seven (7) year plan for eligible transmission, distribution, and storage system improvements; and
>
> (3) identify projected effects of the plan described in subdivision (2) on retail rates and charges.
>
> The public utility shall provide a copy of the petition to the office of the utility consumer counselor when the petition is filed with the commission.

(a) Customer Class Revenue Allocation under Ind. Code § 8-1-39-9(a)(1).

Consistent with Ind. Code § 8-1-39-9(a)(1), NIPSCO is requesting approval to use its customer class revenue allocation factor based on firm load that was approved in the 2010 Rate Order. Exhibit 2, Schedule 4 (Revised Page 1) shows the approved allocation. Having rejected the OUCC's proposal concerning the allocation of distribution related TDSIC costs, and because no other evidence was presented opposing the accuracy of NIPSCO's proposed cost allocation methodology in this Cause, we find that NIPSCO's proposal to allocate approved capital expenditures and TDSIC costs have been properly allocated to the various customer classes in accordance with Ind. Code §8-1-39-9 (a)(1).

(b) NIPSCO's Current 7-Year Gas Plan under Ind. Code § 8-1-39-9(a)(2).

As part of its case-in-chief, NIPSCO attached its Approved Plan as well as its proposed Updated Plan. Therefore, NIPSCO has satisfied the requirement set forth in Ind. Code § 8-1-39-9(a)(2). We note that in each semi-annual TDSIC filing, NIPSCO must update its 7-Year Gas Plan pursuant to Ind. Code § 8-1-39-9(a) and in accordance with the specific parameters set forth in our Order in Cause No. 44403.

(c) Projected Effect on Retail Rates and Charges as Required by Ind. Code § 8-1-39-9(a)(3).

Mr. Isensee sponsored Exhibit 2, Schedule 6, which identifies: (1) NIPSCO's original calculation of the projected effect of the 7-Year Gas Plan on retail rates and charges included in NIPSCO's original case in chief in Cause No. 44403; (2) the projected effect of the Approved Plan on retail rates and charges based on ratemaking provisions as proposed in this proceeding; and (3) the projected effect of the Updated Plan on retail rates and charges based on ratemaking provisions as proposed in this proceeding. Exhibit 2, Schedule 6 also summarizes the total estimated revenue requirement for each rate class from 2014 to 2020. Finally, Mr. Isensee testified the estimated average monthly bill impact for a typical residential customer using 72 therms per month is $0.06.

Based on our review of the evidence, we find that NIPSCO provided sufficient information regarding the projected effects of the Updated Plan on retail rates and charges as required by Ind. Code § 8-1-39-9(a)(3).

(d) Past and Future Rate Case Timing and TDSIC Timing.

Ind. Code § 8-1-39-9(c) states that "[e]xcept as provided in section 15 of this chapter, a public utility may not file a petition under subsection (a) within nine (9) months after the date on which the commission issues an order changing the public utility's basic rates and charges with respect to the same type of utility service." Mr. Shambo testified that NIPSCO's current basic gas rates and charges were set by the Commission's 2010 Rate Order. We find that Cause No. 44403-TDSIC-1 was filed more than nine (9) months after NIPSCO's last general rate case in accordance with Ind. Code § 8-1-39-9(c).

Ind. 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." Mr. Shambo testified that NIPSCO intends to comply with this requirement, and we find that NIPSCO shall petition the Commission for review and approval of NIPSCO's basic gas rates and charges before the expiration of NIPSCO's 7-Year Electric Plan pursuant to Ind. Code § 8-1-39-9(d).

Ind. Code § 8-1-39-9(e) states that "[a] public utility may file a petition under this section not more than one (1) time every six (6) months." Mr. Shambo testified that NIPSCO intends to file a petition for a TDSIC adjustment for the timely recovery of its TDSIC costs approximately every six months. Mr. Isensee testified that NIPSCO proposes to file its petition and case in chief by September 1 and March 1 each year with new rates becoming effective for the 6 month periods starting on December 1 and June 1, respectively. We find that NIPSCO's filing in this proceeding consistent with Ind. Code § 8-1-39-9(e) and is reasonable.

(e) Billing Period.

In this proceeding, NIPSCO requests approval of TDSIC factors to be applicable to bills during the months of February 2015 through May 2015 to effectuate the timely recovery of 80% of TDSIC costs incurred in connection with NIPSCO's eligible transmission, distribution, and storage system improvements. Mr. Isensee testified the TDSIC factors include TDSIC costs incurred through June 30, 2014.

(f) Semi-Annual Revenue Requirement – Capital.

In this proceeding, NIPSCO requests approval of a total adjusted semi-annual revenue requirement associated with a return on eligible transmission, distribution, and storage system improvements ("T&D Assets") incurred through June 30, 2014 of $215,725 (Exhibit 1, Revised Schedule 5, Line 3). The 80% recoverable adjusted semi-annual revenue requirement associated with a return on the T&D Assets is $172,580 (Exhibit 1, Revised Schedule 5, Line 9). The 20% portion of the adjusted semi-annual revenue requirement associated with a return on the T&D Assets is $43,145 (Exhibit 1, Revised Schedule 5, Line 6).

The total cost of the eligible T&D Assets incurred through June 30, 2014, upon which NIPSCO requests authority to earn a return is $4,448,773 (Exhibit 1, Second Revised Schedule 2, Line 3). Mr. Isensee testified this total includes an AFUDC, other indirect costs, and is net of accumulated depreciation. Mr. Isensee testified the AFUDC related to TDSIC projects was calculated in accordance with the instructions of the Federal Energy Regulatory Commission or NARUC Uniform System of Accounts, which is consistent with GAAP. Mr. Isensee testified that if the Commission approves the proposed ratemaking treatment for costs of eligible T&D Assets incurred through June 30, 2014, NIPSCO will cease accruing AFUDC on construction costs once the incurred costs receive CWIP ratemaking treatment, are otherwise reflected in base gas rates, or the project is placed in service, whichever occurs first.

NIPSCO proposes to use a full WACC, including zero-cost capital, to calculate pretax return and provided that the WACC should be updated in each semi-annual TDSIC filing to reflect an updated capital structure and cost of debt. The calculation of NIPSCO's updated total weighted cost of capital is shown on Exhibit 2, Schedule 1. Mr. Isensee explained that the annual revenue requirement for the return on investment is calculated by multiplying the June 30, 2014 net book value of all transmission, distribution and storage system projects by the debt and equity components of NIPSCO's weighted cost of capital. The product of this calculation is then multiplied by 50% in order to calculate a semi-annual revenue requirement. This semi-annual amount is then multiplied by the revenue conversion factor, as discussed below, and further reduced to 80%, as seen in Exhibit 1, Revised Schedule 5, in order to determine the total return-related revenue requirement to be recovered for bills rendered for the months of February through May 2015.

Having rejected the Industrial Group's proposal concerning the appropriate cost of equity to be included in the calculation of pretax return, no other evidence was presented that contested NIPSCO's calculation of the semi-annual revenue requirement. Therefore, based on the record evidence, we find that NIPSCO's request to begin earning a return on the value of the eligible transmission, distribution, and storage system improvements incurred through June 30, 2014 set forth above, complies with the TDSIC tracker methodology approved herein and should be approved. We further find that NIPSCO's proposed total semi-annual revenue requirement associated with the T&D Assets and the 80% recoverable semi-annual revenue requirement as set forth above have been calculated in compliance with the TDSIC tracker methodology approved herein and should be approved.

(g) **<u>Reconciliation.</u>**

Mr. Isensee testified NIPSCO is not including a reconciliation of revenues and costs in this filing as this is the first filing for this mechanism and no previous factors were in effect. The first reconciliation of revenues and costs included in this proceeding will be included in TDSIC-3, which will be filed in September of 2015.

(h) **<u>Calculation of TDSIC Factors.</u>**

Mr. Isensee sponsored Exhibit 1, Revised Schedule 8, which shows the calculation of the TDSIC factors by rate code based on the total adjusted semi-annual revenue requirement of $341,101 (Exhibit 1, Revised Schedule 5, Line 12). He testified the factors are calculated by combining the various components of the allocated revenue requirement and dividing those components by forecasted volumes to compute a billing factor for bills rendered during the months of February through May 2015. Mr. Isensee sponsored Revised Exhibit 3 (Appendix F – Transmission, Distribution and Storage System Improvement Charge (First Revised Sheet No. 157)) showing the TDSIC factors proposed to be applicable for bills rendered during the billing cycles of February through May 2015.

OUCC witness Grosskopf testified that, based on his analysis for Petitioner's proposed TDSIC Factors for the billing period of February through May 2015, NIPSCO's proposed TDSIC tracking factors appear to comport with the ratemaking and accounting treatment authorized by the Statute. OUCC Witness Rutter recommended acceptance of the revised exhibits filed by NIPSCO to remove $37,392 of costs that were incurred prior to March 1, 2014 from the total amount of investment in transmission, distribution, and storage system improvements upon which Petitioner seeks to earn a return. That revision was incorporated into revisions filed with the Commission on November 19, 2014 and incorporated into the record at the evidentiary hearing.

Based on the record evidence, we approve the proposed TDSIC factors set forth in Petitioner's Revised Exhibit 3 to be applicable to bills rendered during the months of February through May 2015 or until replaced by new factors. We decline to adopt the OUCC's request to make the factors approved in this TDSIC-1 proceeding interim and subject to refund pending the outcome the appeals the Commission's Orders in Cause Nos. 44370 and 44371.

(i) **<u>Deferred TDSIC Costs.</u>**

In this proceeding, Mr. Isensee sponsored Exhibit 1, Revised Schedule 9 which shows 20% of the total revenue requirements calculated in Exhibit 1, Revised Schedule 5. He testified the amount included in Column F represents ongoing carrying charges, based on NIPSCO's WACC, on all TDSIC costs deferred through June 30, 2014. He stated these costs will be included for recovery in NIPSCO's base rates in its next general rate case. Based on the record evidence, we find that the costs to be deferred and recovered in NIPSCO's base rates in its next general rate case is $86,242 (Exhibit 1, Revised Schedule 9, Line 12) in accordance with the TDSIC tracker methodology approved herein.

(j) <u>Average Aggregate Increase in Total Retail Revenues Under Ind. Code § 8-1-39-14.</u>

Ind. Code § 8-1-39-14(a) provides that:

> The commission may not approve a TDSIC that would result in an average aggregate increase in a public utility's total retail revenues of more than two percent (2%) in a twelve (12) month period. For purposes of this subsection, a public utility's total retail revenues do not include TDSIC revenues associated with a target economic development project.

Mr. Isensee sponsored <u>Exhibit 1</u>, Revised Schedule 8, which shows that there is no amount in excess of 2% of retail revenues for the past 12 months. Mr. Isensee testified that in accordance with the 44371 Order approving NIPSCO's electric TDSIC, NIPSCO has calculated the 2% cap by comparing the increase in TDSIC revenues in a given year with the total retail revenues for the past 12 months. He stated the retail revenues used in this calculation represent the revenues related to the 12 months ended June 30, 2014 obtained from Cause No. 43629 GCA-31. Based on this evidence, we find that NIPSCO's proposed TDSIC-1 factors will not result in an average aggregate increase in NIPSCO's total retail revenues of more than two percent (2%) in a twelve (12) month period.

6. <u>Confidential Information.</u> NIPSCO filed a motion for protective order on August 28, 2014 which was 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 September 11, 2014 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. NIPSCO is authorized to implement its TDSIC Rate Schedule as described in Petitioner's Exhibit No. 4 pursuant to Ind. Code § 8-1-39-9(a) to effectuate the timely recovery of 80% of eligible and approved capital expenditures and TDSIC costs;

2. NIPSCO's proposed method of calculating pretax return under Ind. Code § 8-1-39-13 is hereby approved;

3. NIPSCO is authorized to defer all TDSIC costs, including depreciation, pretax returns, AFUDC, post in service carrying costs, O&M and property taxes, on an interim basis, until such costs are recognized for ratemaking purposes through Petitioner's proposed TDSIC mechanism or otherwise included for recovery in NIPSCO's base rates in its next general rate case;

4. NIPSCO's proposed allocation methodology approved in Finding No. 5.b. is hereby approved;

5. NIPSCO is authorized to adjust its authorized net operating income to reflect any approved earnings associated with the TDSIC for purposes of Ind. Code § 8-1-2-42(g)(3)(c) pursuant to Ind. Code § 8-1-39-13(b);

6. NIPSCO is authorized to defer and recover 80% of the approved TDSIC costs incurred in connection with the eligible transmission, distribution, and storage improvements identified in Finding No. 5 above in its rates and charges for gas service in accordance with NIPSCO's TDSIC beginning with the February 2015 billing month.

7. NIPSCO's requested TDSIC factors set forth in Petitioner's Exhibit No. DJI-2 (Revised Page 2), to become effective for bills rendered by NIPSCO during the billing months of February 2015 through May 2015 or until replaced by different factors approved in a subsequent filing are approved as set out in Finding No. 5.h. above;

8. NIPSCO shall file with the Natural Gas Division of the Commission, prior to placing in effect the TDSIC factors approved above, an amendment to its rate schedule with reasonable reference therein reflecting that such charges are applicable to the rate schedules reflected on the amendment.

9. NIPSCO is authorized to defer 20% of the TDSIC costs incurred in connection with the eligible transmission, distribution, and storage improvements described in Finding No. 5 above, and recover those deferred costs in its next general rate case and NIPSCO is authorized to record ongoing carrying charges based on the current overall weighted average cost of capital on all deferred TDSIC costs until such costs are recovered in NIPSCO's base rates as a result of its next general rate case.

10. As discussed in Finding No. 5.a.(1), beginning in TDSIC-2, NIPSCO is authorized to defer and recover 25% of the approved TDSIC costs incurred in connection with the eligible transmission, distribution, and storage improvements related to the 112th Street Project in its rates and charges for gas service in accordance with NIPSCO's TDSIC. NIPSCO is authorized to defer 75% of the TDSIC costs incurred in connection with the eligible transmission, distribution, and storage improvements related to the 112th Street Project and recover those deferred costs in its next general rate case and NIPSCO is authorized to record ongoing carrying charges based on the current overall weighted average cost of capital on all deferred TDSIC costs until such costs are recovered in NIPSCO's base rates as a result of its next general rate case.

11. NIPSCO's Updated 7-Year Gas Plan as set forth in <u>Revised Exhibit Gas Plan Update-1 (Confidential)</u>, including the updated project lists and project cost estimates for 2014 and 2015 and the updated annual projected spends for the remaining years of the Plan, with the exception of bare steel (2016-2020), are hereby approved and the projects included in the Updated Plan are designated as eligible transmission, distribution, and storage system improvements under Ind. Code § 8-1-39-2. NIPSCO is hereby authorized to recover 80% of the costs incurred in connection with the Updated Plan through the TDSIC and to defer 20% of the TDSIC costs incurred in connection with the Updated Plan, including ongoing carrying charges on all deferred TDSIC costs, for recovery in its next general rate case.

12. The information filed by Petitioner in this Cause pursuant to its Motion 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.

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

STEPHAN, HUSTON, MAYS-MEDLEY, WEBER AND ZIEGNER CONCUR:
APPROVED:

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

____
Brenda A. Howe,
Secretary to the Commission