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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR (1) APPROVAL OF AN ADJUSTMENT TO ITS GAS SERVICE RATES THROUGH ITS TRANSMISSION, DISTRIBUTION, AND STORAGE SYSTEM IMPROVEMENT CHARGE ("TDSIC") RATE SCHEDULE; (2) AUTHORITY TO DEFER 20% OF THE APPROVED CAPITAL EXPENDITURES AND TDSIC COSTS FOR RECOVERY IN PETITIONER'S NEXT GENERAL RATE CASE; AND (3) 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 ORDERS IN CAUSE NOS. 44403 AND 44403-TDSIC-1.	CAUSE NO. 44403 TDSIC 3 APPROVED: MAR 30 2016

ORDER OF THE COMMISSION

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

On August 31, 2015, Northern Indiana Public Service Company ("NIPSCO") filed its Verified Petition with the Indiana Utility Regulatory Commission ("Commission") in this Cause for approval of a new Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") pursuant to Ind. Code ch. 8-1-39. On the same day, NIPSCO filed its direct testimony and exhibits.[1]

The NIPSCO Industrial Group ("Industrial Group") filed a petition to intervene on September 8, 2015 and United States Steel Corporation ("US Steel") filed a petition to intervene on September 24, 2015. The petitions were granted on September 22, 2015 and October 6, 2015, respectively.[2]

On November 5, 2015, the Indiana Office of Utility Consumer Counselor ("OUCC") and the Industrial Group filed their respective direct testimony and exhibits.[3] Also on November 5, 2015, the Industrial Group filed a Motion for Administrative Notice, which was granted on November 17, 2015. The OUCC also filed direct testimony on November 13, 2015. On November

[1] NIPSCO filed corrections to its case-in-chief on October 13, 2015 and December 3, 2015.
[2] Industrial Group filed an Amendment to Appendix A to Petition to Intervene on December 3, 2015. The members of the Industrial Group in this proceeding are ArcelorMittal USA, BP Products North America, Inc., Cargill, Inc., Fiat Chrysler Automotive, Praxair, Inc., and USG Corporation.
[3] Industrial Group filed revised direct testimony on December 3, 2015.

20, 2015, the Industrial Group and US Steel filed cross-answering testimony and NIPSCO filed its rebuttal testimony and exhibits.

On December 3, 2015, the Industrial Group filed a Hearing Brief on Cost Allocation. On that same day, NIPSCO filed responses to two questions set out in two separate docket entries dated December 3, 2015.

An evidentiary hearing was held on December 4, 2015, at 9:30 a.m. in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, the Industrial Group and US Steel appeared and participated. At the hearing, the parties' prefiled evidence was offered and admitted into the record and the witnesses were made available for cross-examination. No member of the public appeared or participated at the hearing.

Based on the applicable law and evidence presented, 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 ("TDSIC Statute"), 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 base rates and charges to provide for timely recovery of 80% of approved capital expenditures and TDSIC costs. Therefore, the Commission has jurisdiction over Petitioner and the 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 northern Indiana.

3. **Background and Relief Requested.** On April 30, 2014, the Commission issued an Order in Cause No. 44403 ("44403 Order") concerning Petitioner's request for approval of a 7-year plan for eligible transmission, distribution and storage system improvements ("7-Year Gas Plan" or "Plan"), pursuant to Ind. Code §§ 8-1-39-10 and 11. In the 44403 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 Ind. 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 certain modifications; (4) NIPSCO's proposed definitions of key terms for purposes of interpreting and applying those terms to NIPSCO's 7-Year Gas Plan are approved; and (5) NIPSCO's proposed process for updating the 7-Year Gas Plan in future semi-annual adjustment proceedings is approved.

On January 28, 2015, the Commission issued an Order in Cause No. 44403 TDSIC 1 ("TDSIC-1 Order") approving, among other things, NIPSCO's updated Plan ("Plan Update-1"), with the exception of certain cost estimates for the 112th Street project and bare steel replacement projects, and designating the projects included in Year 2 as "eligible transmission, distribution, and storage system improvements" under Ind. Code § 8-1-39-2. The Commission approved NIPSCO's proposed methodology for calculating its TDSIC adjustment and authorized NIPSCO's recovery of 80% of its approved capital expenditures and TDSIC costs incurred through June 30, 2014. NIPSCO was authorized to defer the remaining 20% until such costs are recovered in NIPSCO's base rates as a result of its next general rate case.

On February 27, 2015, NIPSCO filed its petition and case-in-chief in Cause No. 44403 TDSIC 2 ("TDSIC-2"). Subsequently, on April 8, 2015, the Court of Appeals of Indiana issued a decision in the appeal of a Commission Order in Cause Nos. 44370 and 44371 (NIPSCO's Electric TDSIC cases), reversing in part, affirming in part, and remanding the case to the Commission. *NIPSCO Indus. Grp. v. N. Ind. Pub. Serv. Co.*, 31 N.E.3d 1 (Ind. Ct. App. 2015) ("Appellate Order"). After discussion with the parties, NIPSCO ultimately moved to dismiss TDSIC-2 with the understanding that it would request to recover approved capital expenditures incurred through June 30, 2015, and TDSIC costs for the period July 1, 2014 through June 30, 2015, in Cause No. 44403 TDSIC 3 ("TDSIC-3"). On June 2, 2015, the Commission dismissed TDSIC-2 without prejudice.

In this TDSIC-3 proceeding, NIPSCO requests:

(a) Approval of the TDSIC factors set forth in Attachment 1, Schedule 7 to the Verified Petition to become effective for bills rendered by NIPSCO for the months of February through May 2016 or until replaced by different factors approved in a subsequent filing;

(b) Approval of Petitioner's revised Appendix F – Transmission, Distribution and Storage System Improvement Charge set forth in Attachment 3 to the Verified Petition, which contains the proposed TDSIC factors;

(c) Authority to defer, as a regulatory asset, 20% of the eligible and approved capital expenditures and TDSIC costs incurred in connection with its Plan Update-1 and record ongoing carrying charges based on the current overall weighted average cost of capital ("WACC") on all deferred TDSIC costs until such costs are included for recovery in NIPSCO's next general rate case;

(d) Authority to defer, as a regulatory asset, for recovery in NIPSCO's next general rate case depreciation expenses and property tax expenses associated with the difference between the amount authorized for the 112th Street project in Cause No. 44403 and the actual cost of the project;

(e) Approval of Petitioner's updated 7-Year Gas Plan ("Plan Update-3"), including actual and proposed estimated capital expenditures and TDSIC costs that exceed the amounts in Plan Update-1;

(f) Authority to recover 80% of eligible and approved capital expenditures and TDSIC costs in connection with the Plan Update-3 through the TDSIC and authorizing Petitioner to defer, as a regulatory asset, 20% of eligible and approved capital expenditures and TDSIC costs in connection with the Plan Update-3, for recovery in its next general rate case; and

(g) Approval to amend the eight-week prefiling meeting requirement set forth in the 44403 Order to a four-week prefiling meeting requirement.

4. **Evidence Presented.**

A. **NIPSCO's Case-In-Chief.** NIPSCO presented the testimony and exhibits of Timothy R. Caister, Director of Regulatory Policy; Derric J. Isensee, Executive Director, Rates and Regulatory Finance; and Kurt W. Sangster, Vice President, Major Projects.

Mr. Caister testified that as a result of the Appellate Order, and consistent with the level of detail noted by the Commission in *Duke Energy Indiana, Inc.*, Cause No. 44526 (IURC 05/08/2015) and *Indiana Michigan Power Company*, Cause No. 44542 (IURC 05/08/2015), NIPSCO is now providing a detailed project list for each year of the Plan. However, NIPSCO still expects that the upcoming plan year will include more granularity than future years. He stated all of the TDSIC projects included for recovery in this filing were or will be undertaken for the purpose of safety, reliability, system modernization or economic development as required by Ind. Code § 8-1-39-2 and the Rural Gas Extension projects were undertaken for the purpose of extending gas service in rural areas. None of the projects included for recovery in the proposed TDSIC-3 factors were included in NIPSCO's rate base in Cause No. 43894.

Mr. Caister testified that NIPSCO is requesting approval of the 2014 and 2015 Projects designated in the Plan Update-3 that are included for recovery in the proposed TDSIC-3 factors as well as the 2016–2020 Projects designated in the Plan Update-3. In addition, NIPSCO is requesting approval of the updated cost estimates for 2014 Projects and 2015 Projects designated in the Plan Update-3, including actual and proposed estimated capital expenditures and TDSIC costs that exceed the amounts approved in the TDSIC-1 Order. He stated NIPSCO is also requesting approval of the updated cost estimates for 2016–2020 Projects designated in the Plan Update-3, including any proposed estimated capital expenditures and TDSIC costs that exceed the amounts approved in the TDSIC-1 Order.

Mr. Caister testified that in Cause No. 44403, as part of its 7-Year Gas Plan, NIPSCO did not request approval of any specific targeted economic development projects. Although NIPSCO has not undertaken any such projects to date, he stated that NIPSCO continues to work with interested parties on potential projects, and it will continue to keep TDSIC stakeholders informed to the extent the projects are developed enough to present to them prior to submitting in a TDSIC filing.

Mr. Caister testified that the 44403 Order requires that NIPSCO meet with the OUCC and NIPSCO's interested stakeholders at least eight weeks before each tracker filing to discuss the upcoming filing and identify all variances from the approved Plan. He stated that on January 13, 2015, NIPSCO met with the OUCC and interested stakeholders prior to NIPSCO's TDSIC-2 filing. During that meeting, NIPSCO identified known variances for 2014 Projects from the currently approved Plan and anticipated updates that would be submitted on or before March 1. Mr. Caister explained that NIPSCO also proposed that, in an effort to provide more complete information in the future, it would meet with the OUCC and interested stakeholders at approximately four weeks prior to making its semi-annual tracker filings. He explained this would be more useful because NIPSCO will have finalized its updated Plan and will have more current actual costs to inform any cost variances. He stated the OUCC and the interested stakeholders in attendance agreed that a change from meeting eight weeks prior to the filing to one that is four weeks prior will accommodate the intent of the stakeholder meeting, and they settled on a date for the fall prefiling meeting.

Mr. Caister testified that NIPSCO met with the OUCC and interested stakeholders on August 4, 2015, to discuss the upcoming tracker filing and identify all variances from the approved Plan. He indicated that NIPSCO was unaware of any unresolved issues and was not including any major change as part of this proceeding.

Mr. Isensee testified that NIPSCO agreed to a 150-day procedural schedule in this proceeding with an expected order date on or about January 27, 2016. He stated that under the normal 90-day schedule, the factors would be effective for a six-month period from December 2015 through May 2016. He explained that with the extended schedule NIPSCO needed to shorten the period to four months to stay on the normal TDSIC filing schedule. He stated the proposed factors are designed to collect the entire revenue requirement over the four-month period and any differences will be reconciled in Cause No. 44403 TDSIC 5.

Mr. Isensee testified that the total cost of the eligible transmission, distribution, and storage system improvements ("Eligible TDSIC Assets") upon which NIPSCO requests authority to earn a return is $75,235,982. He said this amount includes allowance for funds used during construction ("AFUDC"), other indirect costs, and is net of accumulated depreciation, incurred through June 30, 2015.

Mr. Isensee testified NIPSCO is only seeking approval to recover a return on its investment and the related depreciation expense, property taxes and carrying charges associated with $3,322,780 of the total direct capital costs incurred through June 30, 2015 for the 112th Street project. He stated this amount represents NIPSCO's best estimate provided in Cause No. 44403 and is inclusive of the 20% contingency percentage. He testified that consistent with the TDSIC-1 Order, NIPSCO will defer for recovery in its next base rate case the depreciation expense and property taxes related to the difference between this amount and the actual amount of the project. He testified that the total depreciation and property taxes NIPSCO plans to defer relating to this difference as of June 30, 2015, is $58,718.

Mr. Isensee provided an overview of the indirect capital costs. He stated that indirect capital costs are associated with capital projects and must be capitalized in order to comply with Generally Accepted Accounting Principles ("GAAP"). However, these often cannot be charged directly to a specific capital project work order as they cannot be directly linked to one particular project and tend to be incurred away from the job site. He stated that NIPSCO groups these indirect capital costs into three categories: overheads; stores, freight and handling; and AFUDC. Mr. Isensee stated that NIPSCO has consistently followed this approach internally for both direct and indirect capital costs for years, including during the test year in its last general rate proceeding in Cause No. 43894.

Mr. Isensee testified that the AFUDC related to the TDSIC projects was calculated in accordance with the instructions of the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts and is consistent with GAAP. He stated that NIPSCO will cease accruing AFUDC on construction costs once the incurred costs receive construction work in progress ("CWIP") ratemaking treatment, are otherwise reflected in base gas rates, or the project is placed in service, whichever occurs first. He stated that, after the in-service date, NIPSCO will calculate and include for recovery post-in-service carrying charges ("PISCC") on costs which have been placed into service and are not receiving ratemaking treatment until such costs receive CWIP ratemaking treatment, or are otherwise reflected in base gas rates.

Mr. Isensee testified NIPSCO has calculated the depreciation expense related to TDSIC capital expenditures according to each asset's designated FERC account classification. Each asset, upon being placed in service, is depreciated according to the associated FERC account composite remaining life approved by the Commission's November 4, 2010 Order in Cause No. 43894.

Mr. Isensee testified that even though there was a mutual agreement between the parties to dismiss the TDSIC-2 proceedings, and no new rates have taken effect since the issuance of the TDSIC-1 Order, NIPSCO determined that a cut-off for capital expenditures of June 30, 2015, was appropriate. He stated the amount relating to the return on capital that would have been collected through the TDSIC-2 tracker instead will be captured as additional PISCC amounts and be shown in the balances that are located in Exhibit 1-A, Attachment 1, Schedule 3 of Petitioner's Exhibit 1.

Mr. Isensee testified the calculation of NIPSCO's return portion of the revenue requirement for costs of Eligible TDSIC Assets incurred through June 30, 2015, is shown on Exhibit 1-A, Attachment 1, Corrected Schedule 2 of Petitioner's Exhibit 1. He stated that in this schedule, the annual revenue requirement for the return on investment is calculated by multiplying the June 30, 2015 net book value of all TDSIC projects by the debt and equity components of NIPSCO's WACC. The product of this calculation is then multiplied by 50% to calculate a semi-annual revenue requirement. He explained that this semi-annual amount is then multiplied by the revenue conversion factor and further reduced to 80% to determine the total return-related revenue requirement to be recovered for bills rendered during the months of February through May, 2016. He stated the four-month recovery period will be the period in time that NIPSCO plans to recover the semi-annual revenue requirement.

Mr. Isensee testified Exhibit 1-A, Attachment 1, Schedule 3 of Petitioner's Exhibit 1 shows the PISCC associated with Eligible TDSIC Assets that were placed into service prior to June 30, 2015. He stated that in the TDSIC-1 Order, the Commission authorized NIPSCO to record and recover PISCC at the effective WACC rate over the respective PISCC time period. PISCC is calculated by multiplying the value of costs which have been placed in service and are not receiving ratemaking treatment by NIPSCO's effective WACC rate for the period in which the costs are in-service. Ongoing carrying charges on the PISCC are calculated until such balances are recovered through rates. He stated that in this filing, NIPSCO is proposing recovery of all eligible PISCC charges incurred for the period July 2014 through June 2015.

Mr. Isensee testified that Exhibit 1-A, Attachment 2, Schedule 2 of Petitioner's Exhibit 1 shows the computation of the revenue conversion factor used to compute NIPSCO's pre-tax revenue requirement. He stated the revenue conversion factor is calculated for debt and equity in order to properly synchronize interest for the purpose of calculating the revenue requirement. The state income tax rate used in this computation was determined in accordance with Ind. Code § 6-3-2-1.

Mr. Isensee testified Exhibit 1-A, Attachment 1, Schedule 4 of Petitioner's Exhibit 1 includes depreciation expense, operation and maintenance expense ("O&M"), and property taxes for the period July 2014 through June 2015. He stated these actual expenses and taxes were reduced to 80% to determine the total to be recovered for bills rendered during the months of February through May 2016. He also explained that based on the allocators approved in the TDSIC-1 Order, NIPSCO will allocate 91.1% of O&M expenses related to the Records Project based on the distribution allocator and 8.9% based on the transmission allocator.

Mr. Isensee testified the TDSIC-1 Order approved NIPSCO's proposal to provide an 80% credit to the TDSIC tracker for actual margins received from all new customers added under the rural extension projects. He stated these amounts are calculated on Exhibit 1-A, Attachment 2, Schedule 5 of Petitioner's Exhibit 1 and are computed by obtaining the related customer usage values and billing rate information to compute the total margin billed for the period July 2014 through June 2015.

Mr. Isensee testified the revenue requirement calculated in the TDSIC-1 filing is being reconciled against the actual revenues received from customers during February through May 2015. He stated this under/over recovery analysis is performed as a part of Exhibit 1, Attachment 1, Schedule 6 of Petitioner's Exhibit 1.

Mr. Isensee testified the TDSIC-1 Order approved NIPSCO's proposal to use its customer class revenue allocation factors based on firm load that were approved in Cause No. 43894. The Commission also approved NIPSCO's proposal to refrain from allocating distribution costs to transmission-only customers. Mr. Isensee testified Exhibit 1-A, Attachment 2, Schedule 4 of Petitioner's Exhibit 1 provides the calculation of the allocation factors as approved in the TDSIC-1 Order that NIPSCO used to allocate the related transmission and distribution revenue requirements in this proceeding as shown on Corrected Schedule 7 of that same exhibit.

Mr. Isensee testified that as a result of the Appellate Order, NIPSCO has provided, for informational purposes only, Exhibit 2-A to Petitioner's Exhibit 2 showing an alternate calculation of the TDSIC-3 factors using the allocation factors approved in Cause No. 43894 without any adjustment based on transmission and distribution considerations to allocate approved capital expenditures and TDSIC costs.

The calculation of the TDSIC factors by rate code based on the previously calculated revenue requirements are reflected in Exhibit 1-A, Attachment 1, Corrected Schedule 7 of Petitioner's Exhibit 1. Mr. Isensee stated 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 for the months of February through May 2016. He further testified that there is no amount in excess of 2% of retail revenues for the past 12 months. He stated that in accordance with the TDSIC-1 Order, 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 for the 12 month period ending June 30, 2015.

Mr. Isensee sponsored Exhibit 1-A, Attachment 3 of Petitioner's Exhibit 1, which is a clean and redlined version of NIPSCO's revised 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 months of February through May 2016, or until replaced by different factors that are approved in a subsequent proceeding.

He also sponsored Exhibit 1-A, Attachment 2, Schedule 6 of Petitioner's Exhibit 1, identifying the projected effect of both Plan Update-1 and Plan Update-3 on retail rates and charges and the total estimated revenue requirement for each rate class from 2014 to 2020. Mr. Isensee testified the estimated average monthly bill impact for a typical residential customer using 72 therms per month[4] is $1.33, representing a $1.27 increase from TDSIC-1.

Mr. Isensee testified that in the TDSIC-1 Order, the Commission authorized NIPSCO to defer 20% of the TDSIC costs incurred in connection with the Eligible TDSIC Assets, including ongoing carrying charges based on the current overall WACC, and recover those deferred costs in its next general rate case as allowed by Ind. Code § 8-1-39-9(b). He stated that consistent with this authority, NIPSCO has deferred as a regulatory asset 20% of all TDSIC costs, including depreciation and property tax expenses and all tax expenses recorded as a result of the deferral of 20% of all TDSIC costs for recovery in its next general rate case.

Mr. Sangster testified that Plan Update-1 reflects the TDSIC-1 Order requirements concerning the 112th Street project and the bare steel projects. He stated that consistent with the TDSIC-1 Order, NIPSCO has only included the originally approved cost estimates for the 112th Street project and the bare steel projects in the Plan Update-1.

Mr. Sangster testified the approved Year 1 projects ("2014 Projects") and the approved Year 2 projects ("2015 Projects") are organized into four categories in the Plan Update-1 schedules: (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 extensions). He stated these schedules provide the name of each project as well as the best estimate of the cost approved in the TDSIC-1 Order. Mr. Sangster also sponsored Exhibit 3-A of Petitioner's Exhibit 3 providing a summary of the gas system deliverability, gas system integrity and system integrity data integration project categories.

Mr. Sangster testified that in the TDSIC-1 Order, the Commission approved NIPSCO's proposal to include all rural gas extensions, both those that qualify using the 20-year margin test under Ind. Code § 8-1-39-11 and those that may qualify under NIPSCO's existing line extension policy, and provide an 80% credit to the TDSIC tracker for actual margins received from all new customers added under the rural extensions projects. He stated Plan Update-1 includes a total of

[4] The usage level associated with a residential customer was the usage level included in NIPSCO's last base rate case, Cause No. 43894.

$217,708,105 for rural gas extensions over the 7-Year Gas Plan with $19,211,294 in direct costs associated with rural gas extensions in 2014 and $39,718,338 in direct costs associated with rural gas extensions in 2015.

Mr. Sangster testified the rural extensions projects included in Plan Update-1 and Plan Update-3 are projected to pass the 20-year test identified in Ind. Code § 8-1-39-11. He stated there are two primary methods for NIPSCO to determine whether a new rural business project is eligible for TDSIC treatment: (1) new rural projects that meet the six-year margin test under Rule 6 of NIPSCO's Tariff, and (2) application of the 20-year margin test based on historical data for margin per customer for residential and commercial customers and for connection rates. He explained that the cost of the extension is estimated based on the project design and includes cost estimates for the specific materials and installation costs associated with the project.

He stated the 20-year margin test is based on customer inquiries and interest, and 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 to the inquiring customers that are within the polygon. That design includes items such as routes, amounts of main by size, amounts of service line, and regulator stations. From that design, a cost of installation is estimated. That cost is compared with the projected margins associated with customers expected to connect with the new project over a 20-year period, taking into consideration factors such as connection rates and customer usage for both commercial and residential customers.

Mr. Sangster testified average rural residential and commercial energy usage was estimated using historic NIPSCO rural customer usage. Residential energy usage is relatively constant, while commercial demand can have a wide variance. He stated that for TDSIC rural extensions projects, an estimated average of rural commercial projects completed in 2014 and 2015 was used. The average commercial margin used was $1,020. He explained that before the final system expansion is made, NIPSCO will make contact with the prospective commercial customers to verify demand to confirm that pipe sizing is adequate because commercial accounts could represent usages that vary from the heat supplied to a simple pole barn to a more complicated process load from an asphalt plant, a grain dryer, or an egg-processing plant. He stated a commercial connection rate of 100% of those that request service was assumed, as it has been NIPSCO's experience that once commercial businesses request natural gas service, they normally connect once the main has been installed. Residential connections were projected to occur over the 20-year period at a declining rate over time.

Mr. Sangster testified that while some inputs into the process tend to be reasonably predictable, the assumptions about connection rates are likely to vary from project to project and that other inputs are very difficult to predict. To accommodate for this, NIPSCO updated the inputs used to forecast rural extensions for Plan Update-3 based on the results of 2014 and 2015 actuals and intends to update the inputs each year. He stated that actual costs incurred in 2014 for eligible rural extensions were lower than the estimated cost because fewer customers requested service than NIPSCO assumed. He stated that NIPSCO forecasted a total of 3,306 new rural service line installations would be requested in 2014, but the actual number of new rural service lines installed in 2014 was approximately 2,479. He stated the actual average installation cost per service line was fairly close to the assumptions NIPSCO used.

With respect to NIPSCO's 7-Year Gas Plan, Mr. Sangster testified NIPSCO's Project Managers have been trained and most have been certified as Project Management Professionals. He stated that the Project Controls Team ensures that items such as cost, scope, schedule, and safety are being properly managed. Mr. Sangster testified that NIPSCO evaluates the scope of each project and determines what group within the organization can most cost effectively design and execute the particular scope of work.

Mr. Sangster explained NIPSCO's cost management process as it relates to its Eligible TDSIC Assets. He testified that NIPSCO has made some changes to the way it executes the projects since its TDSIC-1 filing in September of 2014. He stated that beginning in 2015, with the exception of small rural extensions projects that are better handled by the local operating area, the Major Projects department is executing all of the projects in the 7-Year Gas Plan.

Regarding the 112th Street project, Mr. Sangster testified that both Plan Update-1 and Plan Update-3 show the originally approved cost estimate. He sponsored Petitioner's Exhibit 3-C (Confidential) showing the costs incurred to date and the expected costs to be incurred in 2015 related to the 112th Street project. He stated that consistent with the TDSIC-1 Order, NIPSCO requests approval to defer for recovery in its next base rate case the difference between the amount authorized in Cause No. 44403 for recovery and the actual cost of the project. Mr. Sangster testified the 112th Street project was placed in service in December 2014 and is operational. He stated NIPSCO will be completing site restoration activities such as pouring concrete for curbs and sidewalks in 2015.

Mr. Sangster stated that in TDSIC-1, NIPSCO indicated the estimated final cost of the 112th Street project was an increase of $815,231 (approximately 6%) over the previous estimate and that the increased forecast incorporates both the boring activity and the completion of the western interconnection. He explained that since TDSIC-1, NIPSCO's estimate at completion has increased. He stated that even though the previous estimate included a forecast for the boring activity under the railroad tracks at Front Street, it did not capture the full impact of the extension of the work caused by the issues that were associated with the bore. The previously unknown extent of the impacts associated with the railroad track bores at Front Street caused the project to extend the schedule and all support groups associated with the work. The additional costs were for the extended durations of the general contractor, de-watering, environmental inspector, welding inspectors, safety coordinators, construction coordinators, quality assurance and quality control inspectors, engineering support, railroad flaggers, NIPSCO Gas, Measurement, and Testing Group (for overtime only), nitrogen supplier (due to a change in construction sequencing) and other project support costs (e.g. trailer rentals, property rentals, equipment rentals, fuel, utilities). He stated that in addition to the impacts associated with the railroad bores, additional restoration (additional concrete repairs, asphalt replacement, hard surface milling and landscaping) was identified on December 18, 2014. He testified the estimated quantities of the concrete, asphalt, and landscaping restoration are higher than previously estimated.

Mr. Sangster testified that Plan Update-3 includes an update to the 2014 and 2015 Projects to capture any changes since the TDSIC-1 filing. He stated that Plan Update-3 shows new projects that were not previously included as a 2014 or 2015 Project, updates to project costs, and an explanation for any variance in project cost as well as a list of the 2014 Projects that have been carried over to the 2015 Projects. He stated Plan Update-3 also includes the detailed project list and cost estimates for 2016 and provides project lists and cost estimates for each year of the Plan.

Mr. Sangster testified that since TDSIC-1, NIPSCO has updated the actual costs associated with the projects through June 30, 2015, and has updated and refined the cost estimates for the remaining 2015 Projects. He stated NIPSCO modified the 2015 engineering scopes relative to the seven gas transmission replacement projects and the bare steel project in Gary, Indiana and added five emergent system deliverability projects to the 2015 Projects based on imminent need. He stated that these additions are offset by decreases in costs for the rural extensions projects. He explained that the reduction in the rural extension cost is due to fewer customers requesting services than predicted and fewer six-to-one mains projects developing than were predicted. He explained that the reductions have resulted in the total Plan cost estimate for 2015 being lower than what was approved in TDSIC-1.

Mr. Sangster sponsored Petitioner's Exhibit 3-D (Confidential), NIPSCO's updated Gas Infrastructure Study Risk Model ("Risk Model") that was prepared in July 2015 by EN Engineering in support of the Plan Update-3. He stated the Risk Model shows the current risk-based modeling used to identify and prioritize the transmission pipeline replacement projects in Plan Update-1 as well as Plan Update-3 within the gas system integrity segment. He stated that under the Risk Model, NIPSCO Projects 1, 2, 3, 4, 6, 7 and 9 in Table 3: "Group Project Risk Ranking" will be performed in NIPSCO's 7-Year Gas Plan. Projects 1, 2, 3, 7 and 9 entail replacement of transmission pipe that allow Project 4 (which is a reduction in pressure) and Project 6 (which is the retirement of a 30-inch transmission main) to be completed without the need to replace those pipe sections as well. Under the Risk Model, Projects 5 and 8 in Table 3: "Group Project Risk Ranking" will be evaluated and completed, if required, in the years following the current Plan. Those projects without a NIPSCO Project Number are not scheduled to be performed during the 7-Year Gas Plan but NIPSCO instead will continue to monitor those projects in accordance with its current transmission integrity management plan.

Mr. Sangster testified the Risk Model was used in conjunction with internal expert input to develop the investments included in Plan Update-3. He explained that consistent with the filing procedures provided in the 44403 Order, NIPSCO updated the Risk Model used to prioritize the transmission pipeline replacements projects prior to the TDSIC-3 filing and will do so again prior to its next TDSIC filing. He also provided a summary of the lessons NIPSCO has learned so far in updating the Plan.

Mr. Sangster testified the total expenditures associated with NIPSCO's investment in Eligible TDSIC Assets as of June 30, 2015 is $63,291,955 for direct capital expenditures, $11,336,799 for indirect capital expenditures, and $836,374 in AFUDC for capital expenditures. Additionally, he discussed the plan update process and how the Appellate Order resulted in NIPSCO providing a detailed project list for each year of the Plan.

Mr. Sangster provided a summary of the status of the 2014 Projects. He stated that by the end of 2014, many of the 2014 Projects had been completed and were in service. However, due to the normal work order close-out process and the way December 2014 labor costs are reflected on NIPSCO's accounting books, NIPSCO continued to incur some charges associated with these in-service projects in 2015. He stated there is one transmission project, eight distribution projects, and nine storage projects that were not fully completed in 2014 ("carry-over projects"). He stated that three transmission projects have been canceled, partially delayed, or deferred into a future year (including 2015).

Mr. Sangster testified the total direct cost estimate for the 2014 Projects identified in the TDSIC-1 Order was $43,319,767 and the actual direct cost for the 2014 Projects through December 31, 2014, is $35,193,861, a total decrease of $8,125,906. He stated Plan Update-3 shows the approved cost estimate, the updated cost estimate, the variance, and an explanation of the cost variance. He stated that ultimately, all projects started in 2014 have been undertaken for purposes of safety, reliability, or system modernization and were not included in NIPSCO's rate base in its most recent general rate case. NIPSCO therefore requests that the Commission approve the updated 2014 Projects as eligible improvements pursuant to Ind. Code § 8-1-39-2.

Regarding the carry-over projects, Mr. Sangster stated there were 18 projects in 2014 that were not fully complete and in-service as of December 31, 2014. He explained that in order to complete these projects, NIPSCO incurred costs in 2015, but because these projects were not identified as 2015 Projects in Plan Update-1, NIPSCO added these carry-over projects to the 2015 Projects in Plan Update-3 along with the expected costs to complete these projects.

Mr. Sangster provided an explanation of the three transmission projects that have been canceled, partially delayed, or deferred into a future year. He also provided an explanation of the two new transmission projects, five new distribution projects, and one new storage system improvement that were not identified as 2014 Projects in Plan Update-1.

Mr. Sangster identified the 2014 Projects with noteworthy cost increases and explained what drove the variance for those projects. He stated that six of the 2014 Projects show a cost increase over what was approved in TDSIC-1. He stated that explanations for these variances were included in Plan Update-3. He stated that of the six projects showing a cost increase, only three of those projects show a cost increase of more $100,000, or more than 20% over what was approved in TDSIC-1.

Mr. Sangster testified NIPSCO is in various stages of engineering and construction on the majority of the 2015 Projects. He stated that based on current progress, NIPSCO anticipates the vast majority of the 2015 Projects and all of the 2014 carry-over projects to be completed by year end. He said that for projects that are not completed by December 31, 2015, NIPSCO anticipates that the projects will be in-service but may require additional site restoration work in 2016.

Mr. Sangster identified the variances in expected direct costs for the 2015 Projects as compared to the best estimates of the direct costs identified in the TDSIC-1 Order. He testified that since TDSIC-1, NIPSCO has updated and refined the cost estimates for the 2015 Projects. He testified the total direct capital cost estimate for the 2015 Projects identified in the TDSIC-1 Order was $101,981,148, and the revised total direct capital cost estimate based on information to date for the 2015 Projects is $93,594,752, a total decrease of $8,386,396. He stated Plan Update-3 shows the approved cost estimate, the updated cost estimate, the variance, and an explanation of the cost variance. He testified that ultimately, all projects to be started in 2015 will be undertaken for purposes of safety, reliability, or system modernization and were not included in NIPSCO's rate base in its most recent general rate case. NIPSCO requests that the Commission approve the updated 2015 Projects as eligible improvements pursuant to Ind. Code § 8-1-39-2.

Mr. Sangster explained NIPSCO's rationale for updating and refining the cost estimates for the 2015 Projects. He stated that a cost estimate is developed at a point in time, and it is based on the information known when the estimate is developed. As the project progresses, the information used as inputs into the cost estimation process becomes more accurate. There are different techniques used by project managers to develop a cost estimate for a project, but those methods are only as good as the information that is available.

Mr. Sangster testified best practices for project management call for updating and refining cost estimates as the project proceeds. He stated it is a good practice to use the most recent data, both actual costs and other industry benchmarks for estimating projects. In addition, the practice of updating prior to actual work commencing helps NIPSCO manage the portfolio of projects and overall risk because actual costs and the most recent data better reflect the current market conditions relative to the industry and therefore generate the best estimates at that time. He stated that updating also helps to identify changes over time, specifically related to either constructability impacts or environmental conditions. Furthermore, refining cost estimates as the projects progress helps NIPSCO to identify and mitigate risks.

He explained that the process of reviewing and updating project cost estimates is done in the normal course of project management and portfolio management, but now the information gleaned through this process is incorporated into NIPSCO's TDSIC filings. He stated this also helps ensure that in each plan update, the cost estimate will be based on current information and represent the best estimate of cost for the projects at the time of the filing.

Mr. Sangster identified the 2015 Projects with noteworthy cost increases and explained what drove the variance for those projects. He stated that explanations for these variances were included in Plan Update-3. He provided an explanation of the 11 projects having updated cost estimates that exceed the amount approved in TDSIC-1 by either $100,000 or 20%.

Mr. Sangster testified NIPSCO is proposing to add one 2015 Project to perform detailed engineering for the entire portfolio of seven transmission pipeline replacement segments in 2015 and procure materials for construction. NIPSCO is also proposing to delay the construction of two transmission pipeline replacement segments that were originally planned to have construction initiated in 2015.

He explained that in applying the recommendation from the TDSIC-1 Order, NIPSCO has changed its engineering approach to this portfolio of projects. To that end, the transmission pipeline replacement projects engineering scope for 2015 will be increased to cover all seven transmission pipeline replacement projects. He explained that the Pipeline Safety Team has been involved with the decision to engineer the portfolio of projects up front, followed by the construction of the portfolio. He testified that expediting the detailed engineering and revising the execution plans for the overall transmission pipeline replacement projects will result in the same risk reduction. He also stated that the original risk analysis order was modified to balance the plan workloads to optimize engineering for the entire portfolio. He stated that engineering for the entire transmission pipeline replacement projects will improve project efficiency through bundling, improve procurement strategies, and has a possibility to improve construction contracts.

Mr. Sangster explained changes to the seven major transmission projects for Plan years 2016–2020. He stated that the project order of the projects was modified after a review of the Risk Model and a subject matter expert meeting involving Gas Operations, Engineering, Gas Integrity and Planning. Mr. Sangster sponsored Petitioner's Exhibit 3-E (Confidential) showing the revised order of the transmission projects along with the changes in cost and associated variance explanations. He stated that with refinement of scopes, the addition of NIPSCO direct costs, site walk-downs, adjusted labor rates, and allowances for real estate it was necessary to spread out the projects beyond 2020 to allow for a balanced plan in both labor and dollars.

Mr. Sangster explained how NIPSCO developed the new engineering cost estimate and the updated cost estimate for the transmission pipeline replacements projects. He stated that NIPSCO issued a request for proposals ("RFPs") to construction contractors in May 2015, with a request that bids remain valid for 12 months. Detailed engineering continued after the RFPs were issued and will continue through the remainder of 2015. He stated NIPSCO has integrated the engineering and the construction RFPs into the updates to the estimates for TDSIC-3 and will continue to do so in future filings. He stated that in developing the updated cost estimates, NIPSCO also incorporated refined scopes with better route information, better easement information, better information about risks in the routes such as railroads or wetlands, more refined lengths of pipe, and better information regarding necessary equipment and regulator station replacement. He testified estimates for general construction services were reviewed and refined, while labor rates and time estimates were adjusted as a result of site walk-downs. Finally, he testified specific allowances for real estate easements were incorporated into the updated cost estimates.

Mr. Sangster testified that NIPSCO is proposing to increase the 2015 estimate for the bare steel replacement – engineering for 2016 and 2017 Gary bare steel projects. He stated the original scope of this work was to start engineering for 2016 and 2017 Gary bare steel projects. He testified that NIPSCO has increased the scope of the 2015 engineering work, and has revised the cost estimate to include physical excavation to locate existing laterals that will need to be replaced and includes the environmental studies that are needed. He explained that completing 2016 and 2017 engineering in 2015 will allow NIPSCO to provide a best estimate for construction costs associated with the work to be performed in 2016 and 2017.

Mr. Sangster explained the changes to the Gary bare steel projects for Plan years 2016–2020. He testified the engineering in 2015 identified a new total of 80 miles of bare steel pipe in Gary, Indiana, which is an increase from the previous assumption. He stated that two methods were employed to identify areas of bare steel pipe. First, information was identified through the Records Project to help focus the efforts to areas that were suspected to be bare steel. In these areas physical excavation of mains and laterals was conducted. Second, corrosion testing methods were used and any pipe that showed no difference between the pipe and the ground was assumed to be bare steel, although these pipes may be bare or have some coating that is missing or degraded. He stated that in either case, if there is any uncoated exposure of the pipe to the earth, this point becomes a location where corrosion can occur in an accelerated manner. He stated that while the original scope of work for the Gary bare steel project was to be executed from 2014 through 2017, this additional mileage and decision to complete the engineering up front has extended the project schedule through 2020.

Mr. Sangster explained that NIPSCO intends to complete engineering and environmental studies to allow for a best estimate for the 2016 and 2017 Gary bare steel project. He stated the engineering proposal includes execution of all associated surveying and excavation investigations and that NIPSCO will have enough engineering complete to issue a RFP in the fourth quarter of 2015. He indicated the detailed engineering will continue through the remainder of 2015. Mr. Sangster also explained how the cost estimates for the bare steel projects for 2016–2020 were developed by EN Engineering using the 80 miles of pipe predicted from the testing criteria.

In addition to the 2014 Projects that are being carried-over to 2015, Mr. Sangster testified that NIPSCO has added eight projects to the 2015 Projects. He provided an explanation for each of the eight projects previously included in the 2014 Projects and how NIPSCO developed the cost estimate for the two new projects, the Shipshewana Main Extension and Regulatory Station and Northern Border Heater Replacement, which were not included in the TDSIC-2 filing.

Mr. Sangster summarized the list of 2016–2020 projects and project groups for Plan Update-3. He testified the 2016–2020 project lists include the following types of projects: large transmission pipeline replacement projects, projects to prepare lines for in-line inspection, shallow pipe replacement, inspect and mitigate project groups (both transmission and distribution), system deliverability projects (both transmission and distribution), bare steel replacement, master meter upgrades, storage project groups. He stated that within the inspect and mitigate and storage project categories, there are project groups that are based upon a preset list of planned projects and project groups in which the work is prioritized based on U.S. Department of Transportation ("DOT") mandated annual inspections. He explained that depending on the results of the inspection, NIPSCO develops a schedule to replace assets that require replacement or take other mitigation actions to reduce risk. This information is then used to identify the specific work to be done within the project group. Mr. Sangster sponsored Petitioner's Exhibit 3-G (Confidential) containing information regarding certain project groups included in 2016–2020.

Mr. Sangster explained how NIPSCO selected the transmission and distribution system deliverability projects for Plan Update-3. He testified that all of the 2016, 2017, and 2018 system deliverability projects resulted from the 2014-2015 winter field readings and the data found during the pre- and post-winter reviews and predicting the results for design day conditions, which are the basis for NIPSCO's gas supply and gas infrastructure. He explained that NIPSCO's gas systems are monitored for deliverability and any pressure alarm or loss of service is reviewed and prioritized. He stated that the system deliverability projects included in the Plan are those where field pressure readings indicate that NIPSCO would experience loss of service under design day conditions.

Mr. Sangster testified the noteworthy updates to the 2016–2020 Plan years include: changes to the schedule and cost for the seven major transmission projects; changes to the scope and cost for the bare steel replacement projects; changes to the schedule for the Kokomo Low Pressure System projects; refinement of scope and cost estimates for the inspect and mitigate category (both transmission and distribution); refinement of scope and cost estimates for the system deliverability category (both transmission and distribution); changes to the forecast for rural extensions projects; and changes to the scope and cost for the Records Project.

Mr. Sangster explained the changes to the Kokomo Low Pressure System projects for Plan years 2016–2020. He stated the engineering/modeling that was expected to take place in 2017 was deferred to 2019, and the project start was moved to 2020 to prioritize higher risk projects (e.g. bare steel replacement). He explained that while the original scope of the Gary bare steel replacement was to be executed from 2014 through 2017, the increase to 80 miles and the decision to complete the engineering upfront has extended the project schedule through 2020. He stated the Gary bare steel replacement project is a higher priority than the Kokomo Low Pressure System project because of the leak history on bare steel and higher operational risk due to the Gary system having a higher operating pressure than Kokomo.

Mr. Sangster explained the changes to the inspect and mitigate categories (both transmission and distribution) for Plan years 2016–2020. He stated the estimated cost for the inspect and mitigate category within transmission has been adjusted to reflect the updated transmission crossing risk model results for replacements and bores. He stated the project group "Mitigation Required from Field Inspections - Transmission" was separated from the "Mitigation Required from Field Inspections – Distribution" as its own project group. These project groups have been added for each year. He stated the inspect and mitigate category within distribution decreases every year due to splitting out the "Mitigation Required from Field Inspections - Transmission" and a reduction in the gas regulator station work.

With regard to the system deliverability projects (both transmission and distribution) for Plan years 2016–2020, Mr. Sangster stated that the estimated cost for the system deliverability project category increased substantially for years 2016–2020 as compared to the Plan Update-1 due to the further definition of project scope, identification of actual tie-in points, determination of probable pipe line routing, real estate impacts, environmental impacts, and project risk identification. He stated the annual post-winter review meeting identified specific emergent deliverability projects in years 2016-2018, which are identified in Plan Update-3. He stated that based on the updated prioritized list and field observations, the projects in years 2016-2018 were updated. He testified that specific projects for 2019-2020 will be identified through the pre-winter and post-winter review process in future years. He stated that actual projects for work through 2018 were scoped and estimated, and from these estimates a fully loaded unit cost was derived to use in estimating the system deliverability projects for years 2019 and 2020.

Mr. Sangster testified that based on previous TDSIC rural extension experience, the inputs for the margin test were updated and the projects were reassessed. The estimated costs for rural extensions projects for 2016–2020 have decreased significantly.

Regarding the Records Project, Mr. Sangster stated that it has been designed to enhance the quality of gas legacy record information to reduce pipeline safety risks. He stated that by increasing the accuracy and robustness of NIPSCO's records through a single source, NIPSCO will be able to provide more precise information, reduce excavation damages due to poor records or locating errors, and enhance overall infrastructure data quality to continuously improve both safety and system reliability. Mr. Sangster sponsored Petitioner's Exhibit 3-H providing an overview and update regarding the Records Project.

Mr. Sangster testified that within NIPSCO's system, excavation damage is one of the highest safety risks. He stated NIPSCO utilizes a federally-mandated operational safety metric to measure the number of excavation damages per one thousand one call locate requests. Approximately two years ago, NIPSCO added additional metrics to track detailed root causes of excavation damages. He said when utilizing these metrics, data shows that most of the excavation damages occur on service lines within our system. As a result, NIPSCO has extended its evaluation of how service lines will be added into the GIS system to ensure that the most value-added solution and approach is selected for the integration service line information into NIPSCO's mapping system. He explained that as NIPSCO reviews its options and as an interim solution, the enhanced service card and linen viewers will be leveraged. He said these viewers will enhance the current capabilities of field personnel to view additional linen information electronically by approximately fifty percent. He stated the actual mining of the service cards will remain on hold, allowing NIPSCO to fully evaluate all viable solutions.

Mr. Sangster testified that although actual costs incurred on this project have and will remain within the overall original forecast for years 2014 and 2015, the effort required to meet the intent of the stated objectives has increased in complexity, which could lead to either an increased cost or a decrease in scope. He stated that at the time of the original filing, NIPSCO lacked the knowledge necessary to accurately evaluate the needs for any data model changes. He explained this was due in large part to the disparate data repositories, which meant the assumptions were significantly off on actual cost and effort to perform the needed enhancements. He stated that through the pre-conversion efforts, NIPSCO was better able to identify the true scope of the project. He stated that higher than anticipated market prices have contributed to an increase in required funding of $3.7 million. Further, any action regarding the service lines has been placed on hold, pending additional consideration of other solutions, such as global positioning system technology, to ensure the most value-adding solution is implemented. He said the enhanced service card viewer will serve as a stop-gap partial solution to provide more information and ability than what exists today. Consequently, NIPSCO requests approval of a one-year extension in schedule and $3.7 million of additional funding for a total budget of $12.2 million.

Mr. Sangster testified that NIPSCO's Plan Update-3 follows the requirements of the TDSIC Statute by making investments for the purposes of safety, reliability, system modernization, and economic development consistent with public policy and the public interest. He stated NIPSCO has a statutory obligation to provide adequate retail service in its certificated gas service territory and NIPSCO performs this obligation for the public convenience and necessity.

Mr. Sangster testified that the estimated costs of the Eligible TDSIC Assets included in the Plan Update-3 are justified by incremental benefits attributable to the Plan. Mr. Sangster testified that the Plan Update-3 focuses on maintaining safe, reliable service for NIPSCO's customers in a cost effective manner. He stated that while the Plan Update-3 addresses all four types of eligible investment (safety, reliability, system modernization and economic development) in the TDSIC Statute, the emphasis of most of the Plan's investments is to positively impact public safety. Safety drivers focus on risk reduction related to gas system leaks, pipeline ruptures, or incidents of pressure excursion. Reliability drivers include the avoidance of gas outages driven from the inability to maintain gas system pressure during peak load events.

Mr. Sangster testified that the Plan Update-3 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 system integrity data integration program, and the extension of gas facilities into rural areas. He stated the rural extensions projects included in the Plan Update-3 will continue to increase the number of rural customers served over the life of the Plan.

B. <u>OUCC's Case-in-Chief.</u> The OUCC filed the testimony of Leja D. Courter, Director of the Natural Gas Division, Mark H. Grosskopf, a Senior Utility Analyst, and Edward T. Rutter, a Utility Analyst in the Resource Planning and Communications Divisions.

Mr. Courter provided a history of NIPSCO's electric TDSIC proceedings and the Commission's application of the Appellate Order in subsequent TDSIC orders. He testified the Appellate Order requires a seven-year plan include sufficient detail for all years of the plan (and therefore by extension, all projects within the plan), as a prerequisite to the Commission determining if the plan is reasonable and contains the "best" estimates of the costs of those projects as required by Ind. Code § 8-1-39-10(b)(1). He testified the Commission's subsequent orders have referenced, interpreted, and applied that portion of the Appellate Order in other TDSIC cases in a similar fashion.

Mr. Courter testified that the OUCC recommends that projects added to NIPSCO's TDSIC-3 filing that were not included in NIPSCO's original 7-Year Gas Plan be excluded from cost recovery. He stated that because these new projects were not included in the original Plan, their supporting cost detail was not considered in determining whether the Plan was reasonable. He also testified that language in the Appellate Order limits flexibility to expediting or delaying a project necessary in completing the seven-year plan. He stated that new projects are not part of completing the previously approved Plan. He further testified that disallowance of cost recovery in this proceeding does not preclude NIPSCO from seeking recovery of the costs of these additional projects in NIPSCO's next gas base rate case.

Mr. Grosskopf recommended approval of the rate factor calculations shown in Attachment MHG-2 of OUCC Exhibit 2. He stated that the schedules in Attachment MHG-2 have been amended to be consistent with NIPSCO's alternative schedules sponsored by Mr. Isensee. Mr. Grosskopf also removed from his calculations and TDSIC revenue requirements the new projects for which the OUCC had recommended excluding and all associated costs included for recovery. The exclusions resulted in a net reduction of the TDSIC revenue requirement.

Mr. Grosskopf agreed that NIPSCO's proposed aggregate increase in TDSIC revenue is not currently in excess of the 2% retail revenue cap. He also indicated that he had reviewed NIPSCO's TDSIC rate factor calculations and flow of inputs from other schedules. He stated that, aside from his recommendation regarding correction of distribution cost allocation percentages, Schedule 7 operates effectively to calculate accurate TDSIC rate factors. However, he expressed concern that if the next TDSIC proceeding is delayed, there could be an over-collection of the proposed TDSIC-3 factors and recommended that NIPSCO be required to file its next TDSIC proceeding in time to implement rates on June 1, 2016.

Mr. Grosskopf recommended NIPSCO's TDSIC calculation be amended so that distribution and storage costs are allocated to each rate class, using the same allocation percentages as applied to transmission costs.

Mr. Grosskopf agreed that Petitioner removed from its TDSIC recovery calculations the capital expenditures associated with the 112th Street project that exceeded the estimate provided in Cause No. 44403. He also noted that, consistent with the TDSIC-1 Order, NIPSCO will defer, for recovery in its next base rate case, the depreciation and property tax expense related to the difference between the approved amount and the actual amount of the 112th Street project.

Mr. Grosskopf recommended the Commission require NIPSCO to use the 20% of margins from new rural extension customers retained by NIPSCO to offset the 20% of deferred costs in its next general rate case.

Mr. Grosskopf testified that generally Petitioner's TDSIC calculation schedules, Attachment 1, Schedules 1 through 9, and Attachment 2, Schedules 1-6, effectively and accurately calculate and track TDSIC costs and rate factors based on NIPSCO's proposal. He recommended approval of NIPSCO's rate factor calculation methodology with the following exceptions:

(a) The direct costs, AFUDC, overhead, accumulated depreciation, post-in-service carrying costs, depreciation expense, property tax, and O&M expense associated with the new projects included in this proceeding by NIPSCO and not approved by the Commission as part of NIPSCO's original 7-Year Gas Plan should be excluded from cost recovery.

(b) The allocation percentages applied to distribution and storage 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 § 8-1-39-9(a)(1), as supported by the Appellate Order.

(c) NIPSCO's next TDSIC should be filed in time to facilitate recovery of updated rates on June 1, 2016, or otherwise cease recovery of TDSIC-3 rates as of that date. Within its next TDSIC proceeding, NIPSCO should be required to reconcile the TDSIC-1 revenue requirement with actual revenue collected during the six-month period of June through November 2015.

(d) The remaining 20% margin revenue from rural extensions projects should be deferred as used as a credit to the 20% TDSIC revenue deferred over the same period, for a net revenue recovery in NIPSCO's next rate case.

(e) The per therm TDSIC factors calculated on page 14, column (L) of Attachment MHG-2 should be approved for recovery in this TDSIC filing, subject to updated revenue requirement schedules provided by Petitioner reflecting removal of actual accumulated depreciation, depreciation expense, and allocation of post-in-service carrying charge associated with the exclusion of projects as recommended by the OUCC.

Mr. Rutter addressed the supporting project detail and cost estimates provided by NIPSCO and concluded that the detail was sufficient for most, but not all, of NIPSCO's proposed projects. He identified four projects included for 2017 and two projects for 2018 for which there were no estimates provided in NIPSCO's case-in-chief. However, at the evidentiary hearing, Mr. Rutter amended his testimony to indicate that these projects should not be excluded from the Plan for insufficient cost detail. He testified that subsequent to filing his testimony, NIPSCO provided sufficient cost information.

With regard to the Records Project, Mr. Rutter stated that subsequent to the TDSIC-1 Order approving the Records Project, the Commission issued orders in *Duke Energy Indiana*, Cause No. 44526 (IURC 5/8/2015) and *Indiana Michigan Power Company*, Cause No. 44542 (IURC 5/8/2015) finding vegetation management projects were O&M that were not eligible for TDSIC recovery. He suggested that although the Records Project is a valuable project that has obvious safety benefits, the Commission has now determined those two criteria are insufficient to supercede the definitions to TDSIC-eligible projects. He stated the OUCC recommends the Commission determine the TDSIC eligibility of the Records Project.

C. Industrial Group's Case-in-Chief. Nicholas Phillips, Jr., Managing Principal of Brubaker & Associates, Inc., testified regarding his concerns with the changes NIPSCO was proposing to make in this proceeding to its Plan, including deferred or delayed projects, the addition of new projects, and the increases in cost estimates.

Mr. Phillips testified that NIPSCO's transmission-related projects increased $76.4 million for the plan period, which is a 21.4% increase compared to the transmission-related costs approved in TDSIC-1. With regard to transmission pipeline replacement projects and inspect and mitigate Projects, Mr. Phillips testified that the costs have increased primarily due to changes in project scopes and adjusted labor rates. With regard to system deliverability projects, he indicated the changes were related to projects that are not yet defined.

Mr. Phillips expressed concern that the cost estimates of NIPSCO's seven major transmission pipeline replacement projects have increased from $245.6 million to $407.7 million, a 66% increase. He also stated that two of the seven projects, the Aetna to 483# Loop and the 30" State Line to Highland Junction, have been delayed and are not expected to be completed, if at all, until after the end of the seven-year period covered by the Plan. He noted that NIPSCO also proposes to delay the Kokomo Low Pressure System project. Only 23% of the project is now expected to be completed by the end of the 7-Year Gas Plan.

Mr. Phillips testified that NIPSCO seeks to add eight new 2014 projects and eight new 2015 projects. He also testified that NIPSCO added detailed preliminary engineering for projects in the Plan Update-1 as a new line item in this filing. Taking the added engineering as a new project, Mr. Phillips stated the added cost for new projects is $30.8 million. With regard to rural extensions, Mr. Phillips testified that NIPSCO is proposing to revise its projections for the off-setting revenue credit, resulting in an additional $18.9 million in costs to ratepayers.

Mr. Phillips testified there were twenty other 2014 and 2015 projects with cost increases totaling $7.1 million. He identified additional cost increases in the amount of $65.4 million associated with the Records Project, bare steel replacements, and transmission system deliverability projects. Combined, he calculated that NIPSCO's proposed cost increases add up to $160.7 million.

Mr. Phillips testified that NIPSCO has not demonstrated specific justification for the cost increases as the Commission applied that standard in the TDSIC-1 Order. Mr. Phillips testified that NIPSCO's explanations for the increased cost estimates were generally to the effect that labor or materials turned out to be more expensive than previously anticipated, or that NIPSCO revised the scope or determined additional project controls and contractor oversight were appropriate.

Mr. Phillips stated that it is not appropriate to add new projects to the 7-Year Gas Plan after it has been approved by the Commission. He indicated that the 7-Year Gas Plan is not similar to a fuel cost tracker that is meant to recover whatever costs ended up being incurred. Instead, Mr. Phillips testified that the 7-Year Gas Plan is a capital tracker designed to recover costs associated with improvements identified in an approved plan and designated as eligible. He stated that NIPSCO should still make investments identified along the way as needed for reliable natural gas service, but projects outside the approved 7-Year Gas Plan are just like any other expenditure between rate cases, subject to recovery in the same manner as before the TDSIC Statute was enacted. Mr. Phillips recommended that the new projects identified by NIPSCO along with their associated indirect capital and AFUDC costs should be excluded from TDSIC tracker recovery because they were not designated as eligible improvements in the 7-Year Gas Plan. Mr. Phillips also recommended that NIPSCO be held to its representation in the TDSIC-1 proceeding that the net impact of rural extensions would be $5.7 million.

Mr. Phillips expressed concern with the delays in the major transmission projects. He noted that projects which were deemed necessary for reliability or safety were being deferred or delayed, while customers were being asked to pay more for transmission-related project costs. In particular, he noted the project ranked highest in priority relative to the other projects by NIPSCO's consultant, the Aetna to 483# Loop project, is no longer included in the 7-Year Gas Plan.

Regarding system deliverability projects, Mr. Phillips stated that although certain project categories were included and approved in the Plan Update-1 and the process by which those particular improvements would be identified was disclosed, the Appellate Order found a similar approach to be inconsistent with statutory requirements. He recommended that NIPSCO be required to establish and adhere to ascertainable criteria for identifying specific projects within the system deliverability and project group categories for 2016 through 2020.

Mr. Phillips recommended that the rate of return for NIPSCO's TDSIC tracker be adjusted to 5.49%, the rate of return on NIPSCO's fair value rate base in its last gas rate case. The recommendation was due to: reduced risk due to availability of the TDSIC tracker, fair value rate base per 2010 settlement due to over-depreciated assets, the depreciation credit agreed to in Cause No. 43894 is not applicable to TDSIC costs, and NIPSCO's lack of urgency in implementing needed system updates. He testified that it is also appropriate to reflect inflation in NIPSCO's TDSIC return on equity since the benefit to ratepayers from completing the major transmission pipeline replacement projects is being delayed past 2020.

With regard to cost allocation, Mr. Phillips recommended continued use of the allocation methodology approved by the Commission in its TDSIC-1 Order. He testified that NIPSCO is following cost of service principles by correctly separating the transmission investment allocation from the distribution investment allocation since transmission customers do not use distribution mains. He stated removing distribution related costs for these customer results in rates that are reasonable and just – which are required by Indiana law. If the Commission were to allocate distribution costs to transmission customers, Mr. Phillips noted that NIPSCO's total revenues, including gas cost recovery revenue, should be included.

D. Industrial Group's Cross-Answering Testimony. Responding to Mr. Grosskopf's testimony, Mr. Phillips noted that the Commission rejected the OUCC's cost allocation recommendation in the TDSIC-1 Order. He stated that the Commission's finding in TDSIC-1 was reasoned, fair, and appropriate as well as in accordance with cost causation and sound ratemaking.

Mr. Phillips testified that charging customers with costs the Commission has found are not associated with the provision of service to those customers cannot result in rates that are reasonable and just, particularly as those overcharges would be compounded over a seven-year period. He testified it could be difficult to correct those overcharges in a rate case due to the impact on other customers.

Mr. Phillips testified that the TDSIC Statute requires use of the revenue allocation factors approved in the utility's most recent rate case. He stated, however, that the allocation factors from the last NIPSCO gas rate case are significantly different from those in the NIPSCO electric rate case. Unlike the electric case, he noted that the gas rate case did not include any revenue allocation exhibit. Instead, the gas rate case recited specified reductions in revenue for each rate class without stating the revenue requirement for each class or the allocation of revenue requirements between rate classes. Mr. Phillips testified that the OUCC relied on a work paper from the gas rate case expressed in terms of margin, not revenue as provided in the TDSIC Statute.

E. US Steel Cross-Answering Testimony. Richard W. Cuthbert, President of Cuthbert Consulting, Inc., addressed concerns with the proposed customer class allocation factors to be used in this proceeding. Mr. Cuthbert disagreed with Mr. Grosskopf's recommendations for two reasons: (1) since there were no customer class revenue allocation factors based on firm load approved in NIPSCO's most recent base rate case order, it is inappropriate for the Commission to manufacture them as the OUCC suggests; and (2) it would be contrary to ratemaking principles and would not be fair and equitable for the NIPSCO transportation customers that make use of only the transmission gas system to have to pay for TDSIC improvements made to the distribution and storage gas system specifically to serve the needs of distribution customers. He stated it would be unjust and unreasonable to allocate any significant portion of NIPSCO's distribution and storage facility TDSIC costs to transportation customers. Rather, the principle of cost causation requires that the customers that use the distribution facilities – the residential and commercial customers – bear those costs. Mr. Cuthbert recommended the Commission either (1) deny NIPSCO's request for recovery of TDSIC costs because it is impossible to accurately apply the allocation factors required by Ind. Code § 8-1-39-9(a)(1); or (2) continue to use NIPSCO's proposed separated and different customer class allocation factors for transmission TDSIC costs and for distribution and storage TDSIC costs consistent with the TDSIC-1 Order.

F. NIPSCO's Rebuttal Testimony. NIPSCO filed rebuttal testimony of Messrs. Caister and Sangster.

Mr. Caister stated that Section 9(a) of the TDSIC Statute requires a utility to update its plan with each petition for cost recovery. While the TDSIC Statute provides for the ability to include a petition for approval of a TED project, he stated that it does not restrict the updated plan to only adding a TED. Mr. Caister pointed to the Merriam-Webster dictionary definition of update. He stated that based on the plain language in the TDSIC Statute, and the fact that the practical realities of a gas system in a state of constant change, flexibility is necessary and reasonable to ensure that the utility is making investments that systematically and efficiently deliver service integrity to the benefit of customers and the safety of NIPSCO's employees and the public.

In response to the argument that NIPSCO should not be allowed to include new projects as part of its Plan updates, Mr. Caister stated it is reasonable and necessary to include new projects that, consistent with the TDSIC Statute, are planned by the utility as part of its process to make investments that systematically and efficiently deliver service integrity and maintain or improve reliability and safety. He noted that in Cause No. 44403, the OUCC offered testimony to explain why it is reasonable to include new projects that were not approved in the original 7-Year Gas Plan as part of a future plan update.

Mr. Caister testified the TDSIC Statute does not preclude adding new projects as part of an updated plan. Referencing the dictionary definition of update, he stated that an update could not reasonably be interpreted to exclude adding a project to the 7-Year Gas Plan. He further testified that in Cause No. 44403, at pages 17-18 and 20, both the Commission and the OUCC acknowledged that an updated plan might include new projects. Mr. Caister testified both the plain language of the TDSIC Statute and sound regulatory policy support the ability to include new projects in an updated seven-year plan.

Mr. Caister testified that contrary to Mr. Courter's suggestion, the Appellate Order does not preclude adding new projects. He stated that the Appellate Order is silent on the question of whether a utility may include new projects in an updated seven-year plan. He stated that the specific language of the Appellate Order cited by Mr. Courter is in the context of the Court of Appeals' discussion of how much detail is required to approve a seven-year plan under Ind. Code § 8-1-39-10(b). Mr. Caister stated the Appellate Order addresses the issue of how much detail is required to approve a seven-year plan under Ind. Code § 8-1-39-10 – not what is permitted to be included in an updated plan under Ind. Code § 8-1-39-9(a).

Mr. Caister testified that NIPSCO sufficiently explained the increases in cost estimates. He stated that NIPSCO's case-in-chief included variance explanations for every change in cost estimate in Plan Update-3 and a description of changes in cost greater than 20% or $100,000. He testified that NIPSCO met with the parties on August 4, 2015, and among other things, provided background into how it had improved its estimating process and the impact these improvements had on the Plan Update-3. He noted that NIPSCO and the parties agreed to a 150-day procedural schedule to help provide time to review the updated information, including increases to cost estimates.

Mr. Caister testified NIPSCO provided specific justification to explain any actual capital expenditures and TDSIC costs that exceed the approved capital expenditures and TDSIC costs. He stated that as required by Ind. Code § 8-1-39-9(f), NIPSCO's case-in-chief included variance explanations for every 2014 and 2015 Project for which actual capital expenditures and TDSIC costs exceeded the approved cost estimate. He noted that Mr. Sangster also included written direct testimony to describe any changes in cost greater than 20% or $100,000 and was providing further explanation of some of the increases in actual costs in his rebuttal testimony.

In response to the OUCC's recommendation regarding the eligibility of the Records Project, Mr. Caister testified the Records Project is now two years into execution. He stated the Commission approved the Records Project as part of the original 7-Year Gas Plan in its 44403 Order and the Plan Update-1 approved in the TDSIC-1 Order. Mr. Caister noted that in *S. Ind. Gas and Elec. Co. and Ind. Gas Co., Inc. ("Vectren"),* Consolidated Cause Nos. 44429 and 44430 (IURC Aug. 27, 2014), Vectren requested and received a certificate of public convenience and necessity ("CPCN") for a similar project to update its records system.

Mr. Caister testified that as was discussed in the 44403 Order, the Records Project is not the same as ongoing O&M expenditures, but rather, a one-time project that is not part of base rates. He further indicated that if the Commission had not authorized the project for TDSIC treatment, NIPSCO could have sought a CPCN under Senate Enrolled Act 251 because of the efforts NIPSCO is undertaking to enhance the pipeline safety and reliability of its system directed by federally-mandated requirements. He stated that this alternative path would have been similar to the treatment approved by the Commission in Cause No. 44429, in which Vectren proposed to recover costs associated with the imaging of historical documents to improve the reliability of Vectren's system. Mr. Caister testified there are no new facts about the Records Project that would lead to a change in the Commission's previous finding that it is an eligible project. Rather, the facts still support that it is an eligible project, and one that will improve the safety and reliability of NIPSCO's gas system to the benefit of NIPSCO's customers and employees.

Mr. Caister summarized NIPSCO's proposed updates to the rural extensions projects included in Plan Update-3. He stated that NIPSCO updated several inputs used to forecast rural extensions for Plan Update-3 based on the results of the 2014 and 2015 actual costs and intends to update the inputs each year. Specifically, NIPSCO updated the assumptions of expected margin per new customer based on what NIPSCO has experienced for completed projects that were representative samples of a rural extensions project. He stated that many of the residential customers NIPSCO is serving are using natural gas to generate electricity, which has increased the average forecasted residential margin from about $252 to $300. However, NIPSCO found that the average forecasted commercial customer connecting through rural extensions was smaller than anticipated, which meant that the average margin for commercial connections decreased from $4,814 to $1,020. Mr. Caister stated that these are forecasts for the sole purpose of selecting projects.

Mr. Caister explained that NIPSCO also made updates to the assumptions related to customer connections, which are also used as a means of forecasting. He stated NIPSCO adjusted the expected connections based on connection rates found in completed projects. In addition, NIPSCO has started an education campaign to inform those customers along NIPSCO's main who have not previously connected about the process of obtaining service to help meet its expected connection rate of 90%. He stated that NIPSCO used the actual average cost for residential and commercial customers from 2014 and 2015 and moved from separate costs for residential and commercial customers to a combined average of $3,381 per customer regardless of the type of customer. Mr. Caister testified that although all of these changes result in an update to the forecasted margin credit, the cost recovery and margin credit will continue to be based on actual costs and margins.

Mr. Caister disagreed with Mr. Phillips that the net rate revenue attributable to rural extensions projects should be capped at \$5.7 million. He testified that in the TDSIC-1 Order, the Commission approved NIPSCO's proposal to include in its 7-Year Gas Plan all rural gas extensions, both those that qualify using the 20-year margin test under Ind. Code § 8-1-39-11 and those that may qualify under NIPSCO's existing line extension policy. He stated the Commission also approved NIPSCO's proposal to provide a credit to the TDSIC tracker for 80% of actual margins received from all new customers added under the rural extensions policy. Mr. Caister testified it is reasonable, appropriate, and consistent with sound regulatory policy for NIPSCO to continue to review the assumptions used to develop the expected number of rural extensions as well as the expected margin from new rural customers. He stated that unlike other projects included in the Plan, the ultimate scope of the rural extensions projects is not in NIPSCO's full control because customers have to choose to connect. In addition, the assumption for expected margin is important in determining whether a potential project will meet the 20-year test. Mr. Caister testified that for these reasons, it is not appropriate to cap the net revenue impact of the rural extensions projects.

Mr. Caister testified the Commission should reject the OUCC's recommendation to alter the TDSIC-1 Order and require NIPSCO to use the 20% of margins from new rural customers retained by NIPSCO to offset the 20% of deferred costs in the next general rate case. Referring to the basis used in TDSIC-1, he stated that the TDSIC Statute encourages utilities to make investments to serve new customers, but does not require a utility to provide a credit for margin received from new rural customers. He further stated that the Commission has already established the policy as it relates to the rural extensions projects, and the OUCC's recommendation to use the 20% of margins retained by NIPSCO to offset the 20% of deferred costs should be rejected.

In response to Mr. Phillips' recommendation that the Commission alter its TDSIC-1 Order and require NIPSCO to calculate pretax return based on a 5.49% fair value return, Mr. Caister testified the Commission should reject the Industrial Group's attempt to relitigate the issue. Citing to the TDSIC-1 Order, he stated the Commission found that NIPSCO's proposed 9.9% rate of return on equity ("ROE") was appropriate as it was agreed upon by the parties in Cause No. 43894 and then adjusted downward by an inflation factor to reach an agreed-upon fair return. And because inflation is intended to measure change in price over time and the TDSIC investments are new, inflation should not be included in the return on those assets. Mr. Caister testified that based on this, it is appropriate for the Commission to reject the 5.49% fair value return, which is based on an inflation adjusted ROE.

Mr. Caister testified that 5.49% is not an appropriate WACC to use in establishing the return for new TDSIC infrastructure investments. He stated that by suggesting that the fair value rate of return approved in NIPSCO's last gas rate case should be used to establish the return for new TDSIC investments, Mr. Phillips implies that a 7.0% ROE should be the basis for the return on new TDSIC investment. He stated that Mr. Phillips, however, did not explain that it was derived based on a 2.9% downward adjustment for inflation for purposes of settlement. Mr. Caister stated that adopting Mr. Phillips' recommendation would result in an understated pretax return by incorrectly discounting the return based on an inapplicable inflation adjustment.

Mr. Caister testified NIPSCO used the cost allocation method approved by the Commission in its TDSIC-1 Order to allocate the TDSIC costs in this proceeding. He stated that it is appropriate to allocate TDSIC costs in the manner previously approved by the Commission in its 44403 Order because it follows cost causation principals. He stated customer classes that do not use the distribution system should not be allocated costs associated with the distribution system. Mr. Caister noted that the allocation in NIPSCO's last gas rate case (Cause No. 43894) did not include gas costs, which is different from the allocation of revenue approved in NIPSCO's last electric rate case (Cause No. 43969), where the approved revenue allocation included fuel revenues.

In response to Mr. Grosskopf's concern about a possible delay in NIPSCO's next TDSIC proceeding, Mr. Caister testified that NIPSCO intends to file its TDSIC proceeding on or before March 1, 2016, to return to a semi-annual filing cycle.

Mr. Sangster addressed the new projects objected to by the OUCC and the Industrial Group. He testified that not all of the projects listed on Mr. Grosskopf's Attachment MHG-1C (Confidential) are new projects and that the only projects that are truly new projects are those that have been added for the first time in Plan Update-3 in this proceeding. Mr. Sangster testified there are only four new 2015 Projects that were added for the first time in Plan Update-3. He stated that three of the projects shown on Attachment MHG-1C (Confidential) were included in Plan Update-1 and five of the projects were included in Plan Update-2.

Mr. Sangster distinguished between projects that are added to the Plan as a result of NIPSCO's continuous planning process ("planned new projects") versus emergent projects that NIPSCO undertakes to maintain system reliability and safety immediately or soon after identification to replace assets that have failed or have demonstrated an imminent threat of failure that had previously not been planned for replacement ("emergent new projects"). He testified that while considerable analysis and thought went into the development of the 7-Year Gas Plan, it is important to recognize that the Plan is reflective of the characteristics of the gas system and the needs of NIPSCO's customers as they existed at the time the Plan was developed. Over time, asset condition data, the environment surrounding NIPSCO's gas system, and customer demands evolve. He said new regulations are also expected in the gas integrity area. Mr. Sangster testified that when new knowledge is gained, the Plan will and should be re-prioritized. Mr. Sangster testified that as part of that update process, it is reasonable and preferable for the utility to add planned new projects to the updated plan and, potentially, remove projects from the list as well. He stated it would not be in customers' best interest to hold a utility to the original list of investments if that list is no longer the optimal set of investments.

Mr. Sangster testified that emergent new projects are capital investments that NIPSCO undertakes to replace assets that have failed or have demonstrated an imminent threat of failure that had previously not been planned for replacement. He stated that although emergent new projects are not planned ahead of time, they are new or replacement gas transmission, distribution, or storage projects that NIPSCO undertakes for purposes of safety, reliability, or system modernization and are therefore appropriate to include in an updated plan.

Mr. Sangster testified flexibility is important in developing and executing a long-term infrastructure investment plan. He stated that the duration of the Plan inherently makes it a dynamic process. Information concerning items such as system conditions, number of customers, and new customer impacts to the system cannot be predicted multiple years out with accuracy. He stated that if the Plan were held rigid and no projects could be added, canceled, accelerated or delayed, there is a high likelihood that some projects would be executed that would either be insufficient for customer use or would be unnecessary. He stated there are numerous possible scenarios where the plan, being dynamic as it is, must be allowed to adapt to changing conditions.

Mr. Sangster testified the engineering projects identified by Mr. Phillips on Exhibit NP-2 (Confidential) are not new projects, but instead represent engineering work associated with eligible projects that were approved in the 44403 Order or in the TDSIC-1 Order as Eligible TDSIC Assets. He stated this engineering work is a required and necessary element to complete approved eligible improvements.

Mr. Sangster restated that one of the lessons learned in developing and updating the Plan since the TDSIC-1 filing is that NIPSCO has initiated detailed engineering earlier, when possible and appropriate, to support improved estimate accuracy, enhance procurement strategies, and help generate beneficial construction contract arrangements. As a result, in some cases, NIPSCO will complete engineering work in years prior to the construction start date for a project. He stated that because NIPSCO's 7-Year Gas Plan is organized on a calendar year basis, NIPSCO split out that engineering work into separate line items so that the engineering portion of the project is shown in the year prior to the project's construction start.

He stated that beginning engineering prior to the start of work helps to reduce or avoid various risks and improves the accuracy of the estimate because it reduces the number of surprises encountered by the execution team when work begins. He explained that preliminary engineering can be conducted early in the process and covers areas that tend not to change much with time. This allows for a well-developed scope and an estimate range of ±40% accuracy. He explained that detailed engineering should be conducted as close to the actual work start as possible, due to the fact that detailed engineering takes into account the time sensitive items that were only evaluated on a preliminary basis in the preliminary engineering. He stated that early engineering also helps NIPSCO to integrate safety into the work and pre-engineering allows this process to be much more successful.

Mr. Sangster testified all four of the 2014 engineering projects listed on Mr. Phillips' Exhibit NP-2 (Confidential) were included on the 2014 list approved in the TDSIC-1 Order and the actual cost incurred in 2014 for all four of those projects was less than the estimated cost approved in TDSIC-1. He stated that each of these projects is a stand-alone project on its own line in Plan Update-1.

Mr. Sangster testified three of the four 2015 engineering projects listed on Mr. Phillips' Exhibit NP-2 (Confidential) were included as stand-alone projects on their own line on the 2015 list approved in the TDSIC-1 Order. He stated that the cost estimate for two of the three projects have not changed and the cost estimate for engineering related to the 2016 and 2017 bare steel projects has increased due to a scope increase, but has not changed since NIPSCO filed its case-in-chief in TDSIC-2.

Mr. Sangster testified the majority of the 2015 engineering work relates to the engineering for the transmission pipeline replacement projects, which was included in Plan Update-2 filed in

TDSIC-2 on February 27, 2015. He explained that NIPSCO provided extensive direct testimony to describe why NIPSCO decided to perform all of the engineering work for the large transmission pipeline replacement projects and the bare steel projects up front in both TDSIC-2 and in this proceeding. He stated the engineering for the large transmission pipeline replacement project and the Gary bare steel project was completed for those entire project portfolios to limit continued changes due to detailed engineering being completed in multiple stages. He testified it also provided a more definitive scope of work for these project portfolios and that this information was derived from specific site walk-downs and underground investigation.

Mr. Sangster testified the engineering projects in 2016–2020 shown on Mr. Phillips' Exhibit NP-2 (Confidential) are not new projects. He stated those projects were included in the 2016–2020 Project Categories provided in both TDSIC-1 and TDSIC-2. He explained that this is the first proceeding in which NIPSCO has provided a detailed project list for each year of the Plan. He testified that like other project detail included in TDSIC-3, NIPSCO provided these engineering projects as stand-alone projects intended to allow NIPSCO to engineer projects in advance of project construction.

In response to Mr. Phillips' concern that NIPSCO has delayed or deferred several projects, Mr. Sangster noted that he addressed three 2014 transmission projects that were canceled, partially delayed, or deferred into a future year and explained why these decisions are appropriate in his direct testimony. He testified that prior to making these decisions, NIPSCO carefully evaluated the impact of delaying or deferring these projects and weighed that against the factors that caused the proposed changes. He stated that in each case where a project has been delayed or deferred, NIPSCO has determined that the impact of the delay or deferral will not jeopardize the current level of safety and reliability of NIPSCO's gas system.

Mr. Sangster disagreed with Mr. Phillips' suggestion that the delay in these projects seems largely attributable to NIPSCO's desire for preliminary engineering, which seems driven by refining project cost estimates for ratemaking purposes rather than providing reliable service. He stated that the factors causing the proposed schedule changes include: optimizing schedules for constructability, ensuring that the best project teams can be used to complete the projects most efficiently, ensuring that project resources are not spread too thin in executing the projects, and allocating sufficient time for items such as permitting and land acquisition based on information that has been acquired historically and through additional engineering.

Mr. Sangster explained why NIPSCO deferred the Aetna to 483# Loop project until 2022 given that the updated risk ranking provided in Petitioner's Exhibit 3-D (Confidential) shows that it is the transmission pipeline replacement project with the highest priority ranking. He stated all of the other large transmission pipeline replacement projects in the risk model are existing pipes and the risk analysis was based on probability of failure and consequence of failure. He explained that the Aetna to 483# Loop project is the addition of a piping segment that will act as a secondary gas supply for the 483# system. He stated the new piping segment from Aetna to 483# Loop will act as a redundant feed for the 483# Loop and was analyzed as a means to lower vulnerability of the system. He stated the Aetna to 483# Loop project cannot function until the majority of the other large transmission pipeline replacement projects are completed, so it makes sense to shift the order of these projects and complete the other large transmission pipeline replacement projects first. Mr. Sangster testified that when the other large transmission pipeline replacement projects are complete, the vulnerability of these brand new segments will not be as significant, so the risk that the Aetna to 483# Loop is designed to mitigate will be lower.

Mr. Sangster testified as to his belief that the investments included in Plan Update-3 will result in reliable and safe gas transmission service for NIPSCO's large industrial customers. He noted that NIPSCO has not curtailed gas service to the large industrial customers in the last twenty years and, with the exception of one instance in 2009 caused by a regulator station being struck by a car, there have been no instances of loss of service. He noted that even during the polar vortex in the winter of 2014, NIPSCO's gas transmission system performed reliably. He testified the improvements included in Plan Update-3 will help maintain the current level of safety and reliability of NIPSCO's system and will reduce system risk. He stated that although NIPSCO expects the Aetna to 483# Loop and the 30" State Line to Highland Junction projects to reduce the risk of loss of service to large industrial customers by adding redundancy to NIPSCO's system, NIPSCO's current system is safe and reliable.

In response to Mr. Phillips' recommendation that NIPSCO should be required to establish and adhere to ascertainable criteria for the selection of specific improvements in the system deliverability and project group categories, Mr. Sangster agreed it is appropriate that NIPSCO communicate and adhere to ascertainable criteria for the selection of specific improvements. He stated NIPSCO has long-standing established, ascertainable criteria for the selection of specific system deliverability improvements, which were explained in testimony in Cause No. 44403.

He stated that system deliverability projects are designed to serve customers under design day conditions. NIPSCO's gas systems planning design day criteria is based upon the gas supply or Gas Cost Adjustment ("GCA") criteria. He stated the system deliverability projects are selected when field measurements of pressure, flowrates, ambient temperatures, and gas system modeling indicate serving customers may be at risk. Mr. Sangster testified NIPSCO takes selective field measurements year round through its supervisory control and data acquisition system, chart recorders, and on demand to validate its ability to serve. He stated that when field readings indicate abnormal readings, NIPSCO performs gas system modeling to estimate the effects of serving customers. If the model results estimate customers' service may be at risk, a system deliverability project is designed to improve the gas system. If necessary, mitigation plans are developed to maintain service until system improvements can be constructed.

Mr. Sangster testified that to the extent the Commission and interested stakeholders desire more information about NIPSCO's rolling planning cycle iterations and the criteria by which NIPSCO selects system deliverability projects, NIPSCO will refine its communication regarding this issue to make sure that all stakeholders understand the criteria and the process.

Mr. Sangster described how NIPSCO selects specific improvements within the various project groups. For those project groups that do not have preset lists of planned projects, he stated work is prioritized based on U.S. DOT mandated annual inspections. He stated that if a deficiency is identified as a result of the mandated inspection, NIPSCO must take action to mitigate the condition within a prompt and reasonable time. Mr. Sangster testified that depending on the results of the inspection, NIPSCO develops a schedule to replace assets that require replacement or takes other mitigation actions to reduce risk in conformance with federal regulations. This information is then used to identify the specific work to be done within the project group.

Mr. Sangster testified that in future semi-annual TDSIC proceedings, NIPSCO will provide more detailed information regarding its criteria for the selection of specific improvements for those project groups that do not have preset lists of planned projects. He testified that NIPSCO will also provide more information to show that NIPSCO is adhering to its ascertainable criteria for selection of specific improvements.

Mr. Sangster disagreed with Mr. Phillips' recommendation that the Commission should not approve any increases in costs for system deliverability and project group categories. He testified the Commission should consider changes in cost for the system deliverability projects and project groups in the same manner that other cost estimate changes are evaluated because they face the same cost estimating issues. Mr. Sangster testified it is reasonable for the plan updates filed with each semi-annual TDSIC to include an updated cost estimate for system deliverability projects and project groups.

Regarding Mr. Rutter's concerns that no cost estimates were provided for six system deliverability projects that are scheduled in 2017 and 2018, Mr. Sangster testified that the cost estimates are shown on Pages 26, 27 and 29 of Plan Update-3 (Confidential). He stated each project is shown as a separate line item and listed by name, and there is a best estimate of cost for each project. Mr. Sangster stated that as part of developing Plan Update-3, NIPSCO prepared detailed cost estimates for these six 2017 and 2018 system deliverability projects in May and June 2015, but the estimate forms were simply omitted from Petitioner's Exhibit 3-F (Confidential). After the OUCC brought its concern to NIPSCO's attention, NIPSCO shared the requested estimate forms with the OUCC the next business day. Mr. Sangster provided the detailed estimates that were prepared in May and June of 2015 in Petitioner's Exhibit 3-R-3 (Confidential).

In response to Mr. Phillips' concern that the estimated costs for a number of the projects have increased, Mr. Sangster stated that the TDSIC Statute requires a utility to provide the best estimate of costs for the investments included in the Plan. He testified that the Merriam-Webster definition of estimate uses the words like tentatively, approximately, roughly, and approximate – all of which indicate that an estimate is not equal to a final, actual, or unchangeable value. He noted that the TDSIC Statute does not require a utility to provide a "not-to-exceed" price, or final cost, nor does it preclude the utility from updating the best estimate of the cost of investments in its Plan.

Mr. Sangster testified that NIPSCO shares Mr. Phillips' concern about rising costs of labor, materials, and supplies and has a common goal of completing the projects as cost effectively as possible. He stated that rising cost estimates, however, do not mean that the original estimates were flawed. Rather, it means that the information available upon which to base the cost estimates has changed from the time that the original estimates were prepared. Mr. Sangster testified a cost estimate is developed at a point in time, and it is based on the information known when the estimate is developed. He stated that as the project progresses, the information used as inputs into the cost estimation process becomes more accurate. He stated the cost estimates that support the yet-to-be-completed projects in Plan Update-3 are based on the information known in the spring and summer of 2015 when the Plan Update-3 was prepared.

Mr. Sangster reiterated that the primary drivers of the cost estimate changes for the large transmission pipeline replacement projects include refined scopes, refined general contraction services, adjusted labor rates and time estimates, and specific allowances for real estate easements added. Mr. Sangster noted it was also important to clarify what did not contribute to the cost estimate changes. He stated the cost estimates have not increased due to any delay in bidding the work, improper or inadequate project management, or as a result of a compressed construction schedule. Rather, NIPSCO heeded the direction from the Commission in TDSIC-1 and commenced engineering work for these projects earlier than originally planned, in part to provide more refined cost estimates. Mr. Sangster also explained that with the exception of the stand-alone engineering project, NIPSCO has not begun to incur costs related to these projects yet and this is not a "cost overrun" situation.

Mr. Sangster testified that in reference to Mr. Phillips' testimony and Petitioner's Exhibit 3-E (Confidential), the cost estimates in the April 2014 Estimate line are not escalated, which means they are in 2014 dollars for all years, and the cost estimates in the Updated Estimate line are escalated to 2015 dollars. However, in Plan Update-3, the cost estimates are escalated from the 2015 dollars to the year the project is scheduled. He stated that Mr. Phillips incorrectly refers to the $245.6 million program total as the amount in the Plan Update-1; which was actually from the original Plan and that to accurately compare the cost estimates between the original Plan and Plan Update-3, both sets of costs should be escalated to the scheduled year.

Mr. Sangster testified the primary driver for the change in the cost estimate for the bare steel projects is a scope increase. He explained that NIPSCO has expanded the scope of the engineering work to be completed in 2015 to include physical excavation to locate existing laterals to be replaced and environmental studies. He explained that completing 2016 and 2017 engineering in 2015 will allow NIPSCO to provide a best estimate for construction costs associated with the work to be performed in the future. Accordingly, NIPSCO revised the cost estimate for the engineering work to reflect this increase in scope. He also restated that the scope of the Gary bare steel replacement has increased to 80 miles. While the original scope of the Gary bare steel replacement was to be executed from 2014 through 2017, he said this additional mileage and decision to complete the engineering upfront has extended the project schedule through 2020.

Mr. Sangster testified the change in the cost estimates for the transmission system deliverability investments is primarily due to the identification of more investments that are necessary to maintain system reliability than had been previously identified in Plan Update-1, which was filed on August 28, 2014. He reiterated that the investments identified in Plan Update-3 were identified as a result of NIPSCO's annual post-winter review meeting in April, 2015. He stated that NIPSCO's planning process involves annual spring and fall system review meetings involving operations, Gas Planning and Engineering.

Mr. Sangster testified that in accordance with the plan update process approved in the 44403 Order, this proceeding was the first filing for which NIPSCO was to provide a detailed project list for 2016. He stated that NIPSCO has also provided a detailed project list for 2017-2020. He stated the system deliverability projects are all based upon observed field conditions where delivery issues have been identified and the solution involves installing additional high pressure main and regulation stations to eliminate supply concerns. He testified that the system deliverability projects are necessary to maintain the current level of reliability and safety.

Regarding the Records Project, Mr. Sangster testified that Petitioner's Exhibit 3-H provides extensive information and the reasons that NIPSCO is requesting approval of a one-year extension in schedule and $3.7 million of additional funding for a total budget of $12.2 million. He stated that by increasing the accuracy and robustness of NIPSCO's records through a single source, it will enable NIPSCO to provide more precise information, reduce excavation damages due to poor records or locating errors as well as enhance the overall infrastructure data quality to continuously improve both safety and system reliability.

As for the specific justification for any actual costs that exceeded the approved estimates as required by Ind. Code § 8-1-39-9(f), Mr. Sangster stated that NIPSCO included variance explanations for every change in cost estimate on Plan Update-3 and described any changes in costs greater than 20% or $100,000. He testified that his direct testimony supports the conclusion that actual cost increases for 2014 projects did not result from inadequate project management and are specifically warranted under the circumstances. He further testified that NIPSCO provided similar evidence to explain the increases in cost estimates for future year projects.

5. Commission Discussion and Findings. Given the intervening Indiana Court of Appeals' and Commission decisions since issuance of the TDSIC-1 Order and the interrelationship of issues presented for our review in this proceeding, we must first address the TDSIC Statute and its requirements in light of those recent decisions and then proceed to consider Petitioner's Plan Update-3 and proposed TDSIC-3 factors.

A. TDSIC Statutory Requirements. Subsequent to the Commission's issuance of the 44403 Order and the TDSIC-1 Order, the Court of Appeals issued an opinion addressing our interpretation and implementation of the TDSIC Statute in the appeal of the Commission's Orders in Cause Nos. 44370 and 44371, NIPSCO's electric TDSIC cases. Specifically, and as relevant to our determinations here, the Appellate Order addressed our approval of a seven-year plan under Ind. Code § 8-1-39-10 ("Section 10") that we found failed to provide sufficient detail to designate the "projects" in Years 2 through 7 as eligible transmission, distribution, and storage system improvements ("eligible improvements"). The Commission, concerned with the lack of detail and attempting to address the utility's need for flexibility, determined sufficient evidence had been presented to presume the categories of spending in the later years were eligible for TDSIC treatment, but would delay making a final determination until closer to the time when the projects were to be completed and could be more defined during an update filed under Ind. Code § 8-1-39-9 ("Section 9"). The Court of Appeals held that the "updating process does not, however, relieve the utility of providing an initial seven-year plan that meets the statutory criteria." *NIPSCO Indus. Grp.*, 31 N.E. 3d at 8. It also determined that not only did the Commission err in approving a seven-year plan "given its lack of detail regarding the projects for years two through seven," but it also erred in creating a legal presumption that those projects would be eligible for TDSIC treatment. *Id.* at 8-9. Consequently, the Appellate Order makes clear that the TDSIC Statute contemplates two separate proceedings – a Section 10 proceeding to approve the plan and designate the eligible improvements and a Section 9 proceeding to track the recovery and deferral of approved capital expenditures and TDSIC costs for those designated eligible improvements and the utility's progress on its approved plan.

The Appellate Order also addressed the Commission's determination concerning the rate allocation factors to be applied in the TDSIC. Ind. Code § 8-1-39-9(a) requires the utility to "use the customer class revenue allocation factor based on firm load approved in the public utility's most recent retail base rate case order…." Rather than use the allocation factors from the settlement agreement approved in NIPSCO's most recent rate case, the Commission approved NIPSCO's request to adjust the revenue allocation factors to remove the non-firm load and the distribution costs for transmission only customers. The Court of Appeals held that the adjustment to remove the non-firm load was within the Commission's discretion and expertise, but that the Commission exceeded its statutory authority by allowing the adjustment of the allocation factors based on transmission and distribution considerations. *NIPSCO Indus. Grp.*, 31 N.E. 3d at 16-17.

Subsequent to the Appellate Order, the Commission also issued Orders addressing the TDSIC Statute in *Duke Energy Ind. Inc.,* Cause No. 44526 (IURC May 8, 2015) and in *Ind. Mich. Power Co.,* Cause No. 44542 (IURC May 8, 2015). In both of those cases, the Commission specifically discussed and analyzed the definition of "eligible transmission, distribution, and storage system improvements" in Ind. Code § 8-1-39-2 ("Section 2") for purposes of determining whether certain proposed projects could be designated as eligible improvements in a seven-year plan.

As recognized by the parties in this Cause, both the Appellate Order and the evidence presented in this proceeding have necessitated a review of our original interpretation of the TDSIC Statute and its implementation as authorized in the 44403 Order. Based on the conclusions in the Appellate Order, it is clear that when approving a seven-year plan under Section 10, the Commission must be satisfied that the proposed projects contain sufficient detail for it to determine that the projects meet the definition of eligible improvements so as to be designated in the plan and approved, without any presumption, as eligible for TDSIC treatment. In this proceeding, NIPSCO seeks to provide additional detail concerning the projects for all seven years of its plan, especially in Year 3 through Year 7, to comport with the Appellate Order and ensure that the Commission has sufficient information to remove the presumption of eligibility for Year 3 through Year 7 and designate the identified projects as eligible improvements.

Although going forward any proposed project will be approved and designated as an eligible improvement in a utility's Section 10 filing of a proposed seven-year plan, we recognize that this case presents a unique situation. While we approved NIPSCO's Plan in the 44403 Order, which is a final order, the Appellate Order makes clear that the Commission exceeded its statutory authority in certain areas. Therefore, although this is a Section 9 proceeding, we must confirm that NIPSCO has set forth sufficient information for the Commission to now designate each of the projects in Plan Update-3 as an eligible improvement.

B. <u>Findings and Conclusions Regarding Plan Update-3</u>. Ind. Code § 8-1-39-9(a) requires a utility to update its seven-year plan as a component of TDSIC periodic automatic adjustment filings. In this case, NIPSCO requests approval of Plan Update-3, which contains updates to the 2014 and 2015 Projects, a detailed project list and cost estimates for each year of the Plan, and updated cost estimates.

As we have indicated in other Commission proceedings, the TDSIC Statute is silent as to what may be included in a Section 9 update and what review is required. Section 9(a) provides that:

> [t]he public utility shall update the public utility's seven (7) year plan … with each petition the public utility files under this section. An update may include a petition for approval of a targeted economic development project under section 11 of this chapter.

In construing a statute, our primary goal is to determine and give effect to the intent of the Legislature. *Ind. Civil Rights Comm'n v. Adler*, 714 N.E.2d 632, 637 (Ind. 1999). When interpreting the words of a single section of a statute, a court must construe them with due regard for all other sections and with regard to the legislative intent to carry out the spirit and purpose of the act. *N.D.F. v. State*, 775 N.E.2d 1085, 1088 (Ind. 2002). Further, when the statute is clear and unambiguous, we need not apply any rules of construction other than to require that words and phrases be given their plain, ordinary, and usual meanings. *City of Carmel v. Steele*, 865 N.E.2d 612, 618 (Ind. 2007).

The Merriam-Webster online dictionary defines "update" as, "to change (something) by including the most recent information; to make (something) more modern; to give (someone) the most recent information about something."[5] The "something" required to be updated in Section 9(a) is the utility's seven-year plan for eligible improvements that was approved as reasonable under Section 10. Although the TDSIC Statute does not include a specific definition of a "seven-year plan," it is clear from a plain reading of Section 10(b) and the Appellate Order that a "seven-year plan" consists of those projects that have been designated as eligible improvements based on the Commission's findings concerning cost estimates, public convenience and necessity, and incremental benefits. Therefore, any update must reflect changes that have occurred to those designated eligible improvements since the utility's last TDSIC filing. In addition, because our approval of the plan as reasonable was based on our determination of the best estimate of the cost of the eligible improvements, whether public convenience and necessity require the eligible improvements, and whether the estimated costs of the eligible improvements are justified by the incremental benefits, it would seem reasonable that any update to the plan would include changes to those factors we considered in approving the plan, i.e., changes in an eligible improvement's cost estimate, necessity, and associated benefits. It may also include a request to approve a targeted economic development project.

There also appears to be some dispute between NIPSCO and the Industrial Group concerning when NIPSCO must justify changes in the costs of eligible improvements. Although Section 9(f) only requires a utility to provide specific justification when *actual* capital expenditures and TDSIC costs exceed *approved* capital expenditures and TDSIC costs, we fully expect that a utility will explain or justify any proposed changes to the cost estimates approved in its seven-year plan or a subsequent Section 9 update when they become known. As explained above, any update should include changes in an eligible improvement's cost estimate, necessity, and associated benefits. Consequently, if a utility fails to include known changes in cost estimates or waits to adequately justify proposed changes until the utility seeks to recover actual expenditures, then it bears the risk of having incurred costs that the Commission may find are not adequately justified or reasonable and therefore, ineligible for cost recovery.

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[5] http://www.merriam-webster.com/dictionary/update

1. New and Emergent Projects. NIPSCO seeks to include in its Plan Update-3 projects that were not identified, either as a specific project or within a project group, in its original approved 7-Year Gas Plan or Plan Update-1. These new projects include both "emergent" projects that NIPSCO has just recently identified and seeks to add to the list of 2014 and 2015 Projects and new projects identified for the first time for inclusion in Year 3 through Year 7.[6] Both the OUCC and the Industrial Group argue that an update should be limited to changes concerning the eligible improvements that were designated in the plan and should not include the addition of new or emergent projects. We agree.

NIPSCO argues in its proposed order that adding a new project based on the most recent information about its gas system falls within the dictionary's definition of update. However, NIPSCO's approved Plan does not consist of its entire gas system. Rather, its approved Plan consists of certain designated eligible improvements. Consequently, NIPSCO's update should address changes to those designated eligible improvements contained in its approved Plan.

We find this plain reading of the term update to be supported when looking at the TDSIC Statute as a whole. If a utility were allowed to change or alter its plan in any manner and without regard to its approved contents, it would defeat the requirement in Section 10 that the Commission evaluate the plan in its entirety to determine whether it is reasonable, to make specific findings concerning the cost estimates and the public convenience and necessity of the proposed eligible improvements, and to determine whether the estimated costs of the proposed eligible improvements are justified by the incremental benefits associated with the plan (i.e., the list of identified projects). The Appellate Order made a clear distinction between the scope of a Section 9 proceeding and that of a Section 10 proceeding. The Court of Appeals held that the Section 9 updating process could not relieve the utility from providing a seven-year plan with sufficient detail to satisfy the Section 10 requirements and allow for the Commission's designation of the eligible improvements. As construed by the Court of Appeals, it is a function of a Section 10 proceeding, not a Section 9 proceeding, to designate eligible improvements. This conclusion is consistent with the definition of eligible improvements in Section 2, which requires that they be either (1) "designated in the public utility's seven (7) year plan and approved by the commission *under section 10 of this chapter* as eligible for TDSIC treatment" or (2) approved as a targeted economic development project. (emphasis added).

In addition, the TDSIC Statute is a capital tracker, not an expense tracker. An expense tracker, such as the gas cost adjustment under Ind. Code § 8-1-2-42(g), permits a utility, within defined limits, to track and reconcile a specified category of costs incurred for a particular period of time. A capital tracker, such as the TDSIC or a compliance project under Ind. Code ch. 8-1-8.4, involves regulatory pre-approval of a defined scope of capital expenditures that the utility is permitted to reflect in rates through periodic adjustments and review without filing a general rate case. The purpose of plan approval under Section 10 is to define or preapprove the set of eligible improvements that are capital in nature and designated as eligible for TDSIC treatment under Section 9. This interpretation is also consistent with the timeframes allotted for the review of a

[6] Although NIPSCO initially identified the detailed engineering performed for the seven transmission pipeline replacement projects as a new 2015 project, the engineering costs were simply moved into a separate line item and are not a new project as they are directly related to designated eligible improvements in the Plan.

utility's filings under Sections 9 and 10; Section 10 provides for a longer 210-day review period, whereas Section 9 provides for a shorter 90-day review period.

Although NIPSCO argues that it needs flexibility to adapt to changing conditions over a seven-year period and that it is not in the customer's interest to hold a utility to a list of investments if those investments are no longer optimal, we do not believe that the TDSIC Statute "locks" the utility into making a particular set of investments. As a public utility, NIPSCO has a statutory obligation to provide safe and reliable service – an obligation that existed prior to the TDSIC Statute. Ind. Code § 8-1-2-4. The enactment of the TDSIC Statute simply altered the way in which a utility may seek cost recovery for satisfying that obligation with respect to eligible improvements that the Commission has designated in an approved seven-year plan under Section 10. Therefore, to the extent an investment is deemed appropriate to provide safe and reliable service, NIPSCO is expected to proceed whether tracker recovery under the TDSIC Statute is available or not. Any investments not included among the designated eligible improvements in an approved plan remain subject to cost recovery as authorized by other applicable laws. Likewise, to the extent a designated eligible improvement is no longer considered appropriate or should be revised or delayed, we expect NIPSCO to include that proposed change in its update filed under Section 9.

Accordingly, we deny approval of the new and emergent projects identified in Petitioner's Exhibit 3-R-1 that were not approved and designated as eligible improvements in its Plan Update-1.

2. <u>Eligible Improvements</u>. Section 2 defines eligible improvements as:

> new or replacement electric or gas transmission, distribution, or storage utility projects that:
>
> (1) a public utility undertakes for purposes of safety, reliability, system modernization, or economic development, including the extension of gas service to rural areas;
>
> (2) were not included in the public utility's rate base in its most recent general rate case; and
>
> (3) either were:
>
> (A) designated in the public utility's seven (7) year plan and approved by the commission under section 10 of this chapter as eligible for TDSIC treatment; or
>
> (B) approved as a targeted economic development project under section 11 of this chapter.

The Commission approved and designated (with the exception of any new or emergent projects proposed herein for the first time) NIPSCO's 2014 and 2015 Projects as eligible improvements in the 44403 Order and TDSIC-1 Order, respectively. The proposed projects in Year 3 through Year 7 (i.e., 2016–2020), however, were presumed to be eligible improvements, subject to further definition and specifics being provided through the plan update proceedings. 44403 Order at 24 and 26. As indicated above, the conclusions in the Appellate Order preclude us from continuing to presume the projects in later years are eligible improvements. Therefore, we must confirm that

NIPSCO has set forth sufficient detail for the Commission to affirmatively designate each of the projects in Year 3 through Year 7 as eligible improvements.

NIPSCO provided additional detail in terms of project descriptions and cost estimates for Year 3 through Year 7 in its Plan Update-3 and supporting documentation. Petitioner's Exhibits 1 and 3. Based on the evidence presented and as discussed further below, we find that NIPSCO has presented sufficient detail concerning the majority of the projects and project groups initially approved in the 44403 and TDSIC-1 Orders to affirmatively designate them as eligible improvements. However, before addressing that additional information, we find it necessary to address the continued eligibility of the Records Project and the eligibility of certain project groups.

a. Records Project. The Commission approved the Records Project as part of NIPSCO's Plan in Cause No. 44403 and again in the Plan Update-1 in Cause No. 44403 TDSIC-1. The Records Project is now two years into its execution. The OUCC, noting the Commission's decisions in *Duke Energy Ind., Inc.,* Cause No. 44526 (IURC May 8, 2015) and in *Ind. Mich. Power Co.,* Cause No. 44542 (IURC May 8, 2015) and the extensive discussion concerning the definition of an eligible improvement, recommended we determine whether the Records Project is an eligible improvement.

As noted above, we have already determined the eligibility of the Records Project in the 44403 Order, which is a final order. While it is possible we may arrive at a different conclusion today concerning the Records Project's eligibility for TDSIC treatment based on our decisions in Cause Nos. 44526 and 44542, nothing in the Appellate Order requires us to reconsider our initial approval of the Records Project as an eligible improvement.[7] Therefore, because the Records Project has already been approved as an eligible improvement and is two years into its execution, we decline to reconsider our earlier final decision.

b. Project Groups. In the 44403 Order, the Commission approved certain project groups, which contain some "identified" as well as "yet to be identified" projects. These include system deliverability projects (for both distribution and transmission) and project groups within the inspect and mitigate (for both distribution and transmission) and storage categories of projects, and rural extension projects. The Commission approved these project groups under a presumption of eligibility and authorized NIPSCO to provide additional detail concerning the specific projects in future update proceedings. In response to the Appellate Order, NIPSCO has sought to provide more specificity with respect to the projects in these project groups.

NIPSCO's Plan Update-3 contains a preset list of system deliverability projects for 2016 through 2018, but not for 2019 or 2020 because they will be selected in the future based upon NIPSCO's system planning process. Mr. Sangster explained NIPSCO's planning criteria and assessment practices for selecting the specific system deliverability projects, including the use of gas system modeling and analysis software, to ensure customers are served under Design Day conditions. Petitioner's Exhibit 3-R at 17-20. He stated that projects are selected when field

[7] We note that an administrative agency is not bound by prior policy when that policy proves flawed or in need of change, but the change must be explained and the reasons therefor articulated. *Community Care Centers, Inc. v. Ind. Dept. of Pub. Welfare*, 523 N.E. 2d 448, 451 (Ind. Ct. App. 1988).

measurements of pressure, flowrates, ambient temperatures, and gas system modeling indicate serving customers may be at risk. *Id.* at 19.

With respect to the project groups within the inspect and mitigate and storage categories, these also contain a preset list of planned replacements through 2020 as well as certain asset replacements that are not specifically identified because they are planned and prioritized based on DOT mandated annual inspections. Mr. Sangster explained that if a deficiency is identified during an inspection, federal regulations require certain action be taken to reduce risk. Petitioner's Exhibit 3-R at 21. NIPSCO identifies the specific work to be done and then prioritizes it based on a set list. *Id.* at 21-22.

Similar to these project groups are the rural extension projects, which are identified and determined using either the 6-year margin test under Rule 6 of NIPSCO's tariff or the 20-year margin test based on customer interest and a polygon established to define the area to be served. Petitioner's Exhibit 3 at 8-12.

Based on the evidence presented, we find that NIPSCO has provided ascertainable planning criteria for identifying and selecting the specific improvements that it will undertake in these project groups. Given the planning process involved, we fully expect that once a project has been identified and selected, NIPSCO will include it within its Plan update prior to construction occurring. We also expect that NIPSCO will cooperate fully with the parties to further delineate the criteria NIPSCO utilizes to ensure that the parties have a sufficient understanding of the information used to evaluate whether a particular project satisfies the planning criteria described by NIPSCO.

3. <u>Review of Plan Update-3</u>. Having addressed NIPSCO's proposed new projects, the continued eligibility of the Records Project, and the adequacy of the detail concerning certain project groups, we consider the other changes identified in the Plan Update-3. As discussed above, any update should include a discussion of any changes in an eligible improvement's best estimate of cost, necessity, and associated benefits upon which the Commission based its determination to approve NIPSCO's proposed Plan as reasonable.

a. Cost Estimates. Mr. Sangster testified that Plan Update-3 shows actual costs for the 2014 Projects, updated cost estimates for the 2015 Projects, and cost estimates for the 2016–2020 projects and project groups. Petitioner's Exhibit 3-F (Confidential) provides information to support NIPSCO's revised cost estimates for investments included in Plan Update-3 and includes: (i) detailed cost estimates for 2015 Projects; (ii) project change requests for 2015 Projects that explain all changes from the original estimates; (iii) detailed cost estimates for 2016 Projects, all large transmission projects, and the bare steel replacement project for 2016–2020; and (iv) unit cost estimates for 2016–2020 project groups.

Mr. Sangster testified that based on NIPSCO's experience executing the 2014 and 2015 Projects and the challenges relating to the cost estimate for the 112th Street project, NIPSCO reevaluated its cost estimates for the 2015 Projects to ensure that they reflect realistic assumptions for the use of internal versus external engineering and construction labor, outage durations, and timeframe for work to be completed. The evidence shows that NIPSCO obtained updated estimates from third-party and internal resources, and then compared those estimates to the original estimates provided in the approved 7-Year Gas Plan. NIPSCO then determined whether to adjust the cost estimate for each of the 2015 Projects based on NIPSCO's assessment of the project and the third party's cost estimate. The updated cost estimates for 2015 Projects included in Plan Update-3 reflect the lessons NIPSCO has learned in executing the 7-Year Plan. For example, Mr. Sangster testified that the original cost estimates generally did not include construction management, safety professionals, quality assurance and control personnel, environmental oversight, and the project schedulers, but that these activities are essential to execute these projects in a safe and efficient manner. Mr. Sangster testified that the estimates provided for the 2015 Projects are Class 2 (these estimates are performed at 10 – 70% project definition, have detailed engineering nearly complete, and use bids tendered as development for the estimate).

For 2016, NIPSCO provided detailed cost estimates for projects and unit costs for project groups. The detailed cost estimates for the 2016 Projects are based on site walk downs, subject matter expert input, risk analysis, and environmental condition analysis. The estimates are considered Class 2 or 3 and have an accuracy of +/- 15%. The cost estimates for the 2016 project groups are unit costs and are based on historical experience or similar projects that were executed in earlier years.

The Industrial Group recommended that the Commission disallow recovery through the TDSIC tracker of $160.7 million in direct capital costs attributable to cost increases for which NIPSCO had not provided specific justification, together with associated adjustments for indirect capital and AFUDC. In order arrive at this figure, Mr. Phillips summed up all of the increases in actual costs for the 2014 Projects and estimated future costs for the projects in years 2015-2020. Mr. Phillips did not consider any decreases in costs, which offset the various cost estimate increases.

As discussed above, the Appellate Order makes clear that the Commission's finding of the "best estimate" of the costs of eligible improvements is to be determined in a Section 10 proceeding, where it is a factor to be determined when considering whether a utility's seven-year plan is reasonable and should be approved. Whereas, in a Section 9 proceeding, a utility must update its approved plan, explaining any changes in the best estimate of costs, necessity, or incremental benefits. We also recognized that this case presents a unique situation because of the timing of the Appellate Order after NIPSCO's 7-Year Gas Plan was approved and the need to now consider whether NIPSCO has provided sufficient information for the Commission to affirmatively designate the projects in Year 3 through Year 7 as eligible improvements.

The Merriam-Webster online dictionary defines "estimate" as, "to judge tentatively or approximately the value, worth or significance of; to determine roughly the size, extent, or nature of; to produce a statement of the approximate cost of."[8] The words "tentatively," "approximately," "roughly," and "approximate" all indicate that an estimate is not equal to a final, actual, or firm value. However, the TDSIC Statute also requires the estimate to be "best," which Merriam-Webster defines as, "better than all others in quality or value; most skillful, talented, or successful;

[8] http://www.merriam-webster.com/dictionary/estimate

most appropriate, useful, or helpful."[9] These definitions all indicate that "best" means a qualitative measure beyond mediocre, standard, or average.

When reviewing a utility's "best estimate" of the costs of eligible improvements, we recognize that a cost estimate is developed at a point in time, and it is based on the information known when the estimate is developed. However, information that should have been known, considered, and factored into an estimate but was not, raises serious concern as to whether the estimate is truly a "best estimate," and those associated costs are more likely to be excluded from TDSIC recovery. The use of appropriate estimating techniques is key to determining whether an estimate is reasonable. Based on our review of the evidence as discussed further below, we find that NIPSCO has generally demonstrated acceptable estimating techniques. We also find that best practices for project management call for updating and refining cost estimates as the project proceeds. Therefore, it is reasonable to use the most recent data, both actual costs and other industry benchmarks, for estimating projects.

In addition, the evidence shows the practice of updating estimates prior to beginning work helps NIPSCO manage the portfolio of projects and overall risk. This is because actual costs and the most recent data better reflect the current market conditions relative to the industry and generate the best estimates at that time. The evidence shows that updating also helps to identify changes over time, specifically related to either constructability impacts or environmental conditions. If the program manager knows that one particular project in the portfolio will cost more than the original estimate, the program manager might need to request approval from the program manager's supervisor for additional funds. However, if the program manager also knows two projects will likely cost less than the original estimates, the program manager may be able to balance the portfolio without needing to request additional funds from the supervisor. Furthermore, refining cost estimates as the projects progress helps NIPSCO to identify and mitigate risks.

In evaluating whether NIPSCO provided sufficient explanations for its revised cost estimates, we consider and review the project categories that have the most significant changes in cost estimates.

1. Transmission Pipeline Replacement Projects. Since the TDSIC-1 Order, NIPSCO reevaluated its engineering approach to the large transmission pipeline replacement projects and proposes to increase the scope of the 2015 engineering work to perform detailed engineering for the entire portfolio of seven transmission pipeline replacement segments in 2015 and procure materials for construction. Mr. Sangster explained the cost estimate for the 2015 engineering for seven transmission pipeline replacements projects and provided a detailed explanation of the scope of the engineering.

The Industrial Group recommended that the Commission disallow recovery through the TDSIC tracker of the costs of the 2015 engineering because it is either a "new" project that was not approved in the TDSIC-1 Order or it represents additional costs above initial estimates that were determined to be the "best estimate."

[9] http://www.merriam-webster.com/dictionary/best

Based on our review of the evidence, we find it was reasonable for NIPSCO to change its approach to the engineering for the large transmission pipeline replacement projects and perform detailed engineering for all seven transmission pipeline replacement projects in 2015. NIPSCO explained that engineering for the entire portfolio of transmission pipeline replacement projects is likely to improve project efficiency through bundling, procurement strategies, and possibly construction contracts. The evidence shows that beginning engineering prior to the start of work helps to reduce or avoid various risks. Based on these facts, we conclude that it is reasonable for NIPSCO to perform detailed engineering for the entire portfolio of transmission pipeline replacement projects in 2015 and that NIPSCO has provided the best estimate of this cost.

The evidence also shows that NIPSCO updated the cost estimates for the large transmission pipeline replacement projects to be constructed between 2016 and 2020 and that the revised estimates are notably higher than the original estimates. The Industrial Group expressed concern about the increase in estimates for these projects and recommended the Commission disallow recovery through the TDSIC tracker of costs that exceed the original estimates. The Industrial Group also noted that the overall costs for this category have increased despite the fact that NIPSCO has delayed two of the projects beyond 2020 and excluded the costs of those two projects in Plan Update-3.

At the outset, we note that we share Mr. Phillips' concern about rising costs of labor, materials, and supplies. However, our review of the evidence leads us to conclude that the cost estimate increases are due to changes in the information upon which the original estimates were prepared and such updates are reasonable. Mr. Sangster provided a detailed explanation of all of the new information that has been incorporated into the updated cost estimates for these projects. He testified that NIPSCO issued RFPs to construction contractors in May 2015 with a request that bids remain valid for 12 months. He stated that detailed engineering continued after the RFPs were issued and through the remainder of 2015. Mr. Sangster testified that NIPSCO has integrated the engineering and the construction RFPs into the updated estimates in this proceeding and will continue to do so in future filings. In addition, the evidence shows that, in developing the updated cost estimates, NIPSCO incorporated refined scopes with better information concerning routes, easements, risks in the routes such as railroads or wetlands, lengths of pipe, and equipment/regulator station replacement. The evidence also shows that estimates for general construction services were reviewed and refined, labor rates and time estimates were adjusted as a result of site walk-downs, and specific allowances for real estate easements were incorporated.

Further, we find that the proposed increase in cost estimates for the large transmission pipeline replacement projects is distinguishable from the cost overruns experienced on the 112th Street project. Unlike the 112th Street project, which was a near term, high priority project with a cost estimate for which NIPSCO had expressed a high degree of confidence, the large transmission pipeline replacement projects have later construction start dates with prospective cost estimate changes that are unrelated to any delay in bidding the work or improper or inadequate project management.

Based on our review of the evidence, we find that NIPSCO has sufficiently explained why the $44.5 million increase in the large transmission pipeline replacement projects is reasonable and warranted under the circumstances, and we conclude that the updated detailed cost estimates provided in Petitioner's Exhibit 3-F (Confidential) should be approved.

2. **Bare Steel Replacement Projects.** In TDSIC-1, NIPSCO requested approval to increase its total seven-year budget for the bare steel replacement projects by approximately $8.5 million because NIPSCO believed its original estimate of an 80% mileage replacement rate was incorrect. NIPSCO had determined that a majority of the miles requiring replacement are in the downtown Gary area and include replacement of significantly larger pipe than originally projected. The Commission, noting the projects with increased costs were not scheduled to occur until 2018 and finding the updated cost estimates were not sufficiently detailed, directed NIPSCO to include the projected changes in future TDSIC filings when it could provide a more detailed cost estimate and sufficient justification for any increases.

In this update, NIPSCO increased the scope for the engineering associated with the 2016 and 2017 Gary bare steel projects to include physical excavation to locate existing laterals that will need to be replaced and the environmental studies that are needed. Mr. Sangster testified that completing 2016 and 2017 engineering in 2015 will allow NIPSCO to provide a best estimate for construction costs associated with the work to be performed in 2016 and 2017. NIPSCO also provided an updated cost estimate to reflect the increased scope with an explanation of how the cost estimate for the 2016 and 2017 engineering was developed.

Mr. Sangster testified that engineering in 2015 related to the Gary bare steel projects identified a new total of 80 miles of bare steel pipe in Gary, Indiana, which is an increase from the previous assumption. He testified that, while the original scope of work for the Gary bare steel projects was to be executed from 2014 through 2017, this additional mileage and decision to complete the engineering up front has extended the project schedule through 2020. Mr. Sangster explained that the cost estimates for the bare steel projects for 2016–2020 were developed by EN Engineering. He stated the bare steel project estimates were derived using 80 miles of pipe and provided a detailed description of how the estimates were developed.

Based on our review of the evidence, we find that the change in the cost estimate for the bare steel replacement projects is primarily due to obtaining better information concerning the amount of bare steel pipe to be replaced resulting in a scope increase. The Industrial Group argues that NIPSCO has failed to justify why the cost estimate has increased to $57.4 million from the $27.8 million approved in TDSIC-1. While we share the Industrial Group's concern for the significant increase, we find it reasonable that NIPSCO has expanded the scope of the engineering work to be completed. NIPSCO has also completed the additional engineering related to the Gary bare steel projects that identified a new total of 80 miles of bare steel pipe in Gary, Indiana, which is an increase from the previous assumption. Based on the additional mileage, we conclude that it is reasonable to extend the project schedule through 2020 and to revise the best estimate of costs to include the expanded project scope.

3. **Rural Extensions.** The evidence shows that NIPSCO updated several inputs used to forecast the rural extensions project costs for Plan Update-3 based on the results of the 2014 and 2015 actual costs (and intends to update the inputs each year), which resulted in a substantial decrease in the estimated cost for rural extensions for 2016–2020. Specifically, NIPSCO updated the assumptions of expected margin per new customer based on what NIPSCO has experienced for completed projects that were representative samples of a rural extensions project. Mr. Sangster and Mr. Caister testified that many of the residential customers NIPSCO is serving are using natural gas to generate electricity, which has increased the

average forecasted residential margin from about $252 to $300. However, NIPSCO found that the average forecasted margin for a commercial customer connecting through rural extensions was smaller than anticipated, which meant that the average margin for commercial connections decreased. Mr. Caister testified that NIPSCO has started an education campaign to inform those customers along NIPSCO's main who have not previously connected about the process of obtaining service. This will help NIPSCO meet its expected connection rate of 90%.

Based on our review of the evidence, we find it reasonable for NIPSCO to update the assumptions related to customer connections, average cost for installations, and expected margin per customer based on completed projects. We note that these are forecasts for the purpose of selecting projects and forecasting future costs for Plan Update-3. The cost recovery and margin credit will continue to be based on actual costs and margins.

Although the Industrial Group and the OUCC both argue that the policy regarding the rural extensions margin credit should be amended, which we consider further below, no party submitted evidence disputing the revised estimates. Based on these facts, we conclude that NIPSCO's revised cost estimate for the rural extensions projects and its revised forecasts for margins from rural extensions projects are reasonable.

4. Records Project. In TDSIC-1, Mr. Small testified that the Updated Plan did not reflect any changes in cost or scope for the Records Project, but that the conversion of analog records and incorporation into NIPSCO's digital systems is a very complex process. He explained that greater clarity around project scope and costs could be expected following pre-conversion workshops and pre-production demonstration projects scheduled for completion in December 2014. As part of Plan Update-3, NIPSCO is requesting approval of a one-year extension in the schedule for the Records Project and $3.7 million of additional funding for a total budget of $12.2 million. Mr. Sangster explained that the overall objective of the project (i.e., increasing the accuracy and robustness of NIPSCO's records through a single source) has not changed, but through the pre-conversion process NIPSCO has learned that the required steps for achieving that objective are more complex than originally contemplated. He noted that higher than anticipated market prices have also contributed to the increase in required funding.

As with the 112th Street project, the same principal for reviewing the "best estimate" of the costs of eligible improvements apply. We recognize that a cost estimate is developed at a point in time, and it is based on the information known when the estimate is developed. As stated before, information that should have been known, considered, and factored into an estimate but was not, raises serious concern as to whether the estimate is truly a "best estimate," and those associated costs are more likely to be excluded from TDSIC recovery. Based on our review of the evidence, we find that NIPSCO has generally demonstrated acceptable estimating techniques. We also find that best practices for project management call for updating and refining cost estimates as the project proceeds. Therefore, it is reasonable to use the most recent data, both actual costs and other industry benchmarks, for estimating projects. Thus, we find that NIPSCO has sufficiently explained the issues encountered since its original estimate was approved and why the additional funding is reasonable.

5. Conclusion. Based on the evidence presented, and with the exception of the new and emergent projects discussed above, we find that NIPSCO has provided sufficient detail and explanations for the changes in estimated costs of the eligible improvements included in Plan Update-3. Plan Update-3 includes an explanation for every cost variance: 2014 Projects (pages 3 through 6); 2015 Projects (pages 10 through 12); and 2016–2020 Projects (page 38). NIPSCO provided testimony explaining all 2014 and 2015 Project variances that were greater than 20% or $100,000. In addition, Mr. Rutter testified that NIPSCO provided detailed work order type estimates for the 2014 and 2015 Projects that are still open and in progress, including detailed project change requests for those 2014 and 2015 Projects in which an update was required due to a change in the price of components, a change in the components, and more recent engineering. *See* Petitioner's Exhibit 3-F (Confidential). NIPSCO also provided specific explanations for the changes to the cost estimates for the large transmission pipeline replacement projects, bare steel replacement projects, and rural extensions projects.

We also find that, with the exception of the new and emergent projects discussed above, NIPSCO has provided sufficiently detailed information through Petitioner's Exhibit 3-F (Confidential) to support NIPSCO's best estimate of the cost of the investments included in Plan Update-3. We find that NIPSCO provided detailed cost estimates for 2014, 2015, and 2016 Projects as well as some of the projects beyond 2016, such as the large transmission pipeline replacement projects, which are Class 2 or 3, and identified system delivery projects, which are Class 4. We find that the cost estimates for the remainder of the 2017-2020 projects and project groups, which are unit costs based on historical experience or similar projects that were executed in earlier years, to be reasonable. Accordingly, we find that NIPSCO has provided sufficient information to support the updated best estimates of the cost of the eligible improvements included in Plan Update-3 modified for the exclusions determined above and approved herein, and we approve these as best estimates of the costs for those projects.

b. <u>Public Convenience and Necessity</u>. Mr. Sangster testified that consistent with the initial approved 7-Year Gas Plan, the eligible improvements included in Plan Update-3 will serve the public convenience and necessity. He explained that Plan Update-3 follows the requirements of the TDSIC Statute by making investments for the purposes of safety, reliability, system modernization, and economic development consistent with the public interest. Although the OUCC and Industrial Group argued that the Commission should exclude certain projects and costs included in Plan Update-3, no evidence was presented contesting the public convenience and necessity associated with any of the remaining investments included in Plan Update-3. However, the Industrial Group did express concern with the delay or deferral of certain projects that NIPSCO had previously asserted were of high importance and necessary for safe and reliable service.

In this proceeding, NIPSCO proposes to defer two of the large transmission pipeline replacement projects (the Aetna to 483# Loop project and 30" State Line to Highland Junction project) and delay the start of one project (the Kokomo Low Pressure System) from 2017 to 2019. The Industrial Group expressed concern with the delay of these projects and suggested that the delay seems largely attributable to NIPSCO's desire for preliminary engineering and refining project cost estimates for ratemaking purposes rather than providing reliable service. Mr. Phillips testified concerning the importance of NIPSCO's customers receiving the proper level of system benefits related to the reliable and safe provision of transmission capacity resulting from

NIPSCO's 7-Year Gas Plan as promised. He recommended the Commission closely scrutinize NIPSCO's Plan Update-3 to ensure the updates proposed by NIPSCO are reasonable.

Based on the evidence presented, we find there is sufficient evidence to support NIPSCO's decision to defer or delay these projects. With respect to the Kokomo Low Pressure System project, the evidence shows that NIPSCO elected to delay the start of the Kokomo Low Pressure System from 2017 to 2019 to prioritize higher risk projects, including the bare steel replacement. The evidence shows that NIPSCO deferred the 30" State Line to Highland Junction project pending further records analysis. Mr. Sangster testified that NIPSCO can defer this project because current records indicate a lower probability of failure than the other pipes and lines in the risk model and additional analysis will determine if complete replacement is necessary.

With respect to the Aetna to 483# Loop project, the evidence shows that all of the other large transmission pipeline replacement projects in the risk model are existing pipes. The risk analysis on these piping segments was based on probability of failure and consequence of failure. The Aetna to 483# Loop project is the addition of a piping segment that will act as a secondary gas supply for the 483# system. The new piping segment from Aetna to the 483# Loop will act as a redundant feed for the 483# Loop and was analyzed as a means to lower vulnerability of the system. The evidence shows that the Aetna to 483# Loop project cannot function until the majority of the other large transmission pipeline replacement projects are completed, making it logical to shift the order of these projects and complete the other large transmission pipeline replacement projects first. In addition, the evidence shows that the existing 483# system has been operating reliably without issue for the last twenty years. Although the evidence shows that the Aetna to 483# Loop project and the 30" State Line to Highland Junction project will reduce the risk of loss of service to large industrial customers by adding redundancy to NIPSCO's system, we find that NIPSCO's current transmission system is safe and reliable.

The evidence demonstrates that prior to making these decisions, NIPSCO carefully evaluated the impact of delaying or deferring these projects and weighed the associated possible consequences against the factors that caused the proposed changes. Mr. Sangster testified that in each case where a project has been delayed or deferred, NIPSCO has determined that the impact of the delay or deferral will not jeopardize the current level of safety and reliability of NIPSCO's gas system. Based on our review of the evidence, we conclude that NIPSCO's decision to defer or delay these projects is reasonable.

In conclusion, NIPSCO has a statutory obligation to provide reasonably adequate retail service in its certificated gas service territory for the public convenience and necessity pursuant to Ind. Code §§ 8-1-2-4, -87 and -87.5. With the exception of the new and emergent projects discussed above, we find that NIPSCO has sufficiently supported that the eligible improvements described in Plan Update-3 are reasonably necessary for it to continue to provide adequate retail service to its customers, and the public convenience and necessity requires or will require those eligible improvements.

c. **Incremental Benefits.** Mr. Sangster testified that consistent with the 7-Year Gas Plan, Plan Update-3 focuses on maintaining safe, reliable service for NIPSCO's customers in a cost-effective manner. Plan Update-3 is also 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, the replacement of certain system assets to ensure the ongoing integrity and safe operation of the gas system, investments to enhance pipeline safety and reliability, and the extension of gas facilities into rural areas.

In the 44403 Order (at 23), we found "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." Although the cost estimates for some projects have increased compared to those approved in the 7-Year Gas Plan and Plan Update-1 and some projects have been delayed beyond the 7-Year Gas Plan timeframe, there is no dispute that the eligible improvements included in Plan Update-3 and approved herein provide incremental benefits to NIPSCO's customers.

Based upon the evidence presented in this proceeding and for the reasons set forth above, we find the estimated costs of the eligible improvements included in Plan Update-3 as modified are justified by the incremental benefits attributable to the Plan.

4. Conclusion. Plan Update-3, as modified and approved in this Order, includes sufficient evidence for us to find that it contains the best estimate of the cost of the eligible improvements, the public convenience and necessity continues to require or will require the eligible improvements, and the estimated costs of the eligible improvements continue to be justified by the incremental benefits attributable to Plan Update-3. With the exceptions noted herein, NIPSCO's Plan Update-3 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 extension of service into rural areas.

Based on the evidence presented, we find Plan Update-3 as approved herein to be reasonable and the projects contained in Plan Update-3, with the exception of new and emergent projects that were not identified or approved in NIPSCO's 7-Year Gas Plan or Plan Update-1 as discussed above, are "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code § 8-1-39-2.

C. 8-Week Prefiling Stakeholder Meeting. NIPSCO proposes to change the 8-week prefiling meeting requirement for its Gas TDSIC filing set forth in the 44403 Order to a 4-week prefiling meeting requirement. NIPSCO argued that a 4-week prefiling meeting is more useful than an 8-week prefiling meeting for NIPSCO, the OUCC, and interested stakeholders because at 4 weeks prior to filing, NIPSCO will have finalized its updated plan and will have more current actual costs to inform parties of any cost variances. We expect this change will result in fewer changes between the information NIPSCO presents at the prefiling meeting and the filed information. No party objected to NIPSCO's proposal. Therefore, we approve NIPSCO's proposal to change the 8-week prefiling meeting requirement for its Gas TDSIC filing set forth in the 44403 Order to a 4-week prefiling meeting requirement.

D. Findings and Conclusions Regarding TDSIC-3 Factors. In the TDSIC-1 Order, the Commission approved NIPSCO's request for approval of a TDSIC Rate Schedule and accompanying changes to NIPSCO's gas service tariff to allow for timely recovery of 80% of eligible and approved capital expenditures and TDSIC costs pursuant to Ind. Code § 8-1-39-9.

Consistent with the ratemaking and accounting principles approved by the TDSIC-1 Order, NIPSCO requests approval of its TDSIC-3 factors to provide for timely recovery of 80% of approved capital expenditures and TDSIC costs incurred through June 30, 2015.

1. Section 9 Requirements. Ind. Code § 8-1-39-9(a) provides:

> [s]ubject to subsection (c), 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 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.

a. NIPSCO's 7-Year Gas Plan. As part of its case-in-chief, NIPSCO attached its currently approved 7-Year Gas Plan as well as its proposed Plan Update-3. Therefore, NIPSCO has satisfied the requirement set forth in Ind. Code § 8-1-39-9(a)(2).

b. Customer Class Revenue Allocation. In the TDSIC-1 Order, we approved NIPSCO's proposal that the cost of transmission system improvements be allocated among all customer classes consistent with the revenue allocation from Cause No. 43894, while the cost of distribution system improvements would not be allocated to transportation customers receiving service under Transportation Rates 428 and 438. We also approved NIPSCO's proposal that the cost of storage system improvements would be allocated in the same manner as distribution costs, and the cost of rural extensions projects would be allocated in the same manner as transmission and distribution costs based on the character of the facilities installed. Mr. Isensee testified Exhibit 1-A, Attachment 2, Schedule 4 of Petitioner's Exhibit 1 provides the calculation of the allocation factors as approved in the TDSIC-1 Order, which NIPSCO used to allocate the related transmission and distribution revenue requirements in this proceeding as shown in Exhibit 1-A, Attachment 1, Corrected Schedule 7 of Petitioner's Exhibit 1. Mr. Isensee also provided for informational purposes Petitioner's Exhibit 2, Alternative Attachment 2, Schedule 4, which calculates the TDSIC-3 factors "using the allocation factors approved in Cause No. 43894 without any adjustment based on transmission and distribution considerations to allocate approved capital expenditures and TDSIC costs." Pet.'s Ex. 2 at 18.

The OUCC recommended that NIPSCO's TDSIC calculation be amended so that distribution and storage costs are allocated to each rate class using the same allocation percentages as applied to transmission costs. Mr. Grosskopf testified that NIPSCO's proposed distribution allocation was not approved in NIPSCO's most recent gas retail base rate case order but was approved by the Commission in TDSIC-1. He argued that the language of the Appellate Order supports the position that transmission and distribution costs should be allocated in accordance with NIPSCO's last base rate case order. Mr. Grosskopf agreed with the information in

Petitioner's Exhibit 2, Alternative Attachment 2, Schedule 4, and used the alternate allocation percentages in his calculation of the OUCC's proposed TDSIC factors.

Both the Industrial Group and US Steel disagreed with the OUCC's recommendation to change the cost allocation methodology that was approved in the Commission's TDSIC-1 Order. The Industrial Group's witness, Mr. Phillips, testified that to charge customers for costs the Commission has found are not associated with the provision of service to those customers cannot result in rates that are reasonable and just. He stated these overcharges to Rates 428 and 438 would increase and continue over the seven-year plan period and may be difficult to correct in a rate case due to the impact on other customer classes. Similarly, US Steel's witness, Mr. Cuthbert, disagreed with Mr. Grosskopf's conclusion that the customer class allocation factors it used were explicitly approved by the Commission in NIPSCO's last gas base rate case. He also disagreed that the allocation factors recommended by the OUCC would be appropriate for use in NIPSCO's TDSIC filing or that they would result in just and reasonable rates. Mr. Cuthbert testified the OUCC's proposal would violate a basic tenet of utility ratemaking – cost causation in setting rates.

The question we are presented with is whether the Appellate Order dictates that we deviate from the allocation methodology we approved in the TDSIC-1 Order. We conclude that it does. Noting that Section 9(a) requires the use of "the customer class revenue allocation factor based on firm load approved in the public utility's most recent retail base rate case order," the Court of Appeals found that because the allocation factors from the settlement agreement approved in NIPSCO's last electric base rate case were based on both firm and non-firm load, the Commission's decision to remove the non-firm load portion was within the Commission's discretion and expertise. *NIPSCO Indus. Grp.*, 31 N.E. 3d at 16. However, because the statute "did not require an adjustment for transmission versus distribution considerations," the Commission exceeded its statutory authority by allowing such an adjustment. *Id.* at 17. Although the TDSIC-1 Order is a final order, when the Commission has been apprised that it has exceeded its statutory authority with regard to certain matters, it should adjust its future actions to conform to the law as interpreted by the Court of Appeals.

Although the Industrial Group argued that the Appellate Order is not applicable here because the settlement agreement approved in NIPSCO's last electric base rate case is materially different from the settlement agreement approved in NIPSCO's last gas base rate case, we disagree. In both cases, the approved allocation factors failed to conform to the requirements of Section 9(a). In NIPSCO's electric base rate case, the Commission approved a revenue allocation factor that included both firm and non-firm load. In NIPSCO's last gas base rate, the Commission approved a margin allocation factor, which excluded gas cost recovery revenue. As the Appellate Order affirmed the Commission's discretion to remove the non-firm load to conform the allocation factor to the TDSIC Statute, we find that the Commission has the discretion to require the addition of the gas cost revenue to conform the approved "margin" allocation factor to the "revenue" allocation factor required by the TDSIC Statute.

But the Industrial Group also argued that if the Commission believes the Appellate Order is applicable, then it should make the necessary adjustments to allocate costs based on total revenue. We agree with the Industrial Group that the TDSIC Statute unambiguously calls for the use of "revenue" allocation factors, not "margin" allocations. The "revenue" collected by NIPSCO from various rate classes includes gas cost recovery revenue, not just margin. This is consistent with NIPSCO's application of the 2% cap under Ind. Code § 8-1-39-14(a), wherein NIPSCO includes all of the rate revenue collected from each rate class, inclusive of gas costs, when projecting the impact of the TDSIC tracker on rates and charges.

However, because the TDSIC Statute does not allow for an adjustment for transmission versus distribution considerations, we do not have the authority to make such adjustments in this Order. While we agree that cost allocation that fails to consider transmission and distribution considerations contravenes cost causation principles, the TDSIC Statute as interpreted by the Court of Appeals prohibits those considerations under the facts presented here. Nor does the Industrial Group's argument that the parties' agreement in NIPSCO's last base rate case that rates should be designed to allocate the revenue requirement to customer classes consistent with cost causation principles alter the statutory requirements of Section 9(a).[10]

Accordingly, we find that NIPSCO's approved capital expenditures and TDSIC costs should be allocated to the various customer classes based on total revenue, including gas cost revenue, as set forth in the Industrial Group's Exhibit 1, Table 2 at 23.

c. **Projected Effect on Retail Rates and Charges.** Mr. Isensee sponsored Petitioner's Exhibit 1-A, Attachment 2, Schedule 6 of Petitioner's Exhibit 1, which identifies: (1) the projected effect of Plan Update-1 on retail rates and charges (page 1); and (2) the projected effect of Plan Update-3 on retail rates and charges (page 2). This exhibit 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 $1.33. Based on our review of the evidence, we find that NIPSCO provided sufficient information regarding the projected effects of Plan Update-1 and Plan Update-3 on retail rates and charges as required by Ind. Code § 8-1-39-9(a)(3).

Although we find that NIPSCO has satisfied the statutory requirement to provide the projected effects on retail rates and charges, this Order requires NIPSCO to make changes to its Plan Update-3. Accordingly, NIPSCO shall revise Attachment 2, Schedule 6 consistent with the findings in this Order and submit the revised attachment under this Cause prior to implementing the TDSIC-3 factors.

2. **Reconciliation.** Mr. Isensee testified that NIPSCO is including a reconciliation of revenues in this filing. The revenue requirement calculated in the TDSIC-1 filing is being reconciled against the actual revenues received from customers during February through May 2015. This under/over recovery analysis is performed as a part of Exhibit 1-A, Attachment 1 Schedule 6, of Petitioner's Exhibit 1.

3. **Semi-Annual Revenue Requirement.**

a. **Capital.** In this proceeding, NIPSCO requests approval of a total adjusted semi-annual revenue requirement associated with a return on eligible improvements incurred through June 30, 2015, of $5,631,314 (Exhibit 1-A, Attachment 1, Corrected Schedule 5,

[10] We also note that although the parties agreed how rates *should* be designed, the settlement does not indicate whether the agreed upon rates are consistent with cost causation principles. And, as noted by the OUCC, the application of cost causation principles is not always a bright line application.

Line 3 of Petitioner's Exhibit 1). The 80% recoverable adjusted semi-annual revenue requirement associated with a return on the eligible improvements is $4,505,051 (Id. at Line 9). The 20% portion of the adjusted semi-annual revenue requirement associated with a return on the eligible improvements is $1,126,263 (Id. at Line 6).

The total cost of the eligible improvements incurred through June 30, 2015, upon which NIPSCO requests authority to earn a return is $75,235,982 (Exhibit 1-A, Attachment 1, Corrected Schedule 2, Line 1 of Petitioner's Exhibit 1). Mr. Isensee testified this total includes AFUDC, other indirect costs, and is net of accumulated depreciation. He testified the AFUDC related to TDSIC projects was calculated in accordance with the instructions of the FERC Uniform System of Accounts, which is consistent with GAAP. He further testified that if the Commission approves the proposed ratemaking treatment for costs of the eligible improvements incurred through June 30, 2015, 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.

As we discussed above, the Industrial Group argued the Commission should not allow recovery through the TDSIC tracker of costs in excess of the amounts approved in TDSIC-1. We concluded that NIPSCO has specifically justified why certain costs have increased over the amounts approved in TDSIC-1. Similarly, as discussed above, both the Industrial Group and the OUCC argue that NIPSCO should not be allowed to include new or emergent projects as part of its Plan updates and that the TDSIC-3 factors should not include any costs associated with those projects. To that end, the OUCC's witness, Mr. Grosskopf, calculated alternative TDSIC-3 factors that excluded certain projects that the OUCC considered to be new or emergent. As discussed above, we conclude that certain new and emergent projects should not be included in Plan Update-3. Therefore, we approve $74,107,769 as the total cost of the eligible transmission, distribution, and storage assets incurred through June 30, 2015, upon which NIPSCO is authorized to earn a return.

In TDSIC-1, the Commission ordered NIPSCO 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 WACC is shown on Exhibit 1-A, Attachment 2, Schedule 1 of Petitioner's Exhibit 1. Mr. Isensee explained that the annual revenue requirement for the return on investment is calculated by multiplying the June 30, 2015 net book value of all transmission and distribution projects by the debt and equity components of NIPSCO's WACC. 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 and further reduced to 80%, as seen in Exhibit 1-A, Attachment 1, Corrected Schedule 5 of Petitioner's Exhibit 1, in order to determine the total return-related revenue requirement to be recovered for bills rendered for the months of February through May 2016.

Although we already determined the appropriate ROE and method for determining the WACC to be used in the TDSIC tracker in the TDSIC-1 Order, the Industrial Group again argues that the 5.49% fair value return from the 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. Mr. Phillips argues the Commission should hold NIPSCO accountable for what he considers to be deficiencies in implementing the Plan by reducing the authorized return that was allowed in the TDSIC-1 Order. We disagree.

By suggesting that the fair value rate of return approved in NIPSCO's last gas rate case should be used to establish the return for new TDSIC investments, Mr. Phillips implies that a 7.0% ROE should be the basis for the return on a new TDSIC investment. However, the evidence in this case and our TDSIC-1 Order shows that the 7.0% ROE was derived based on a 2.9% downward adjustment for inflation for purposes of settlement. In our TDSIC-1 Order (at 24), the Commission found that NIPSCO's proposed 9.9% ROE was appropriate, stating "a return on equity of 9.9% was agreed upon in 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. Since the TDSIC investments are new, inflation should not be included in the return on those assets." Nothing about our conclusion in TDSIC-1 has changed – the correct ROE to use from the settlement agreement approved in Cause No. 43894 is 9.9% as used by NIPSCO. Adopting the Industrial Group's recommendation would result in an understated pretax return by incorrectly discounting the return based on an inapplicable inflation adjustment. Consistent with our TDSIC-1 Order, we conclude that the 5.49% fair value WACC that uses an inflation-adjusted ROE is simply not appropriate for establishing the return for new TDSIC infrastructure investments.

Based on the evidence of record, we find the appropriate total semi-annual revenue requirement associated with the eligible improvements as of June 30, 2015 to be $5,561,249 and the 80% recoverable semi-annual revenue requirement $4,445,545 to have been calculated in compliance with the TDSIC tracker methodology approved in the TDSIC-1 Order, and the revenue requirement is approved.

b. Depreciation, O&M Expense, and Property Tax Expenses. In this proceeding, NIPSCO requests approval of a total depreciation, O&M, and property expense through June 30, 2015 of $4,437,233 (Exhibit 1-A, Attachment 1, Corrected Schedule 5, Line 4 of Petitioner's Exhibit 1). The 80% recoverable depreciation, O&M and property tax expense associated with eligible TDSIC projects is $3,549,787 (Id. at Line 10). The 20% portion of the depreciation, O&M and property tax expense associated with eligible TDSIC projects is $887,447 (Id. at Line 7).

Mr. Isensee sponsored Exhibit 1-A, Attachment 1, Schedule 4 of Petitioner's Exhibit 1 showing the actual depreciation expense, O&M (related to the Records Project) and property taxes for the period of July 2014 through June 2015, which was reduced to 80% as shown on Exhibit 1-A, Attachment 1, Corrected Schedule 5 to Petitioner's Exhibit 1, to determine the total revenue requirement to be recovered for bills rendered during the months of February through May 2016..

Based on the evidence of record, we find that NIPSCO's total depreciation, O&M, and property tax expense associated with eligible TDSIC projects through June 30, 2015, is $4,434,237. The 80% recoverable depreciation, O&M, and property tax expense associated with eligible TDSIC projects is $3,547,390. The 20% portion of the depreciation, O&M, and property tax expense associated with eligible TDSIC projects is $886,847. These amounts have been calculated in compliance with the TDSIC tracker methodology approved in the TDSIC-1 Order and are approved.

c. **Margin Credit for Rural Extensions.** In the TDSIC-1 Order, the Commission approved NIPSCO's proposal to include in its 7-Year Gas Plan all rural gas extensions, both those that qualify using the 20-year margin test under Ind. Code § 8-1-39-11 and those that may qualify under NIPSCO's existing line extension policy. The Commission also approved NIPSCO's proposal to provide a credit to the TDSIC tracker for 80% of actual margins received from all new customers added under the rural extensions policy. TDSIC-1 Order at 19, 25-26. In this proceeding, Mr. Isensee testified these amounts are calculated on Exhibit 1-A, Attachment 2, Schedule 5 of Petitioner's Exhibit 1 and are computed by obtaining the related customer usage values and billing rate information to compute the total margin billed for the period of July 2014 through June 2015.

As discussed above, NIPSCO updated several inputs used to forecast rural extensions costs and margins going forward, and both the costs and the margins are now expected to be lower. The Industrial Group and the OUCC both argued that the Commission should change the 80% margin credit policy that we approved in the TDSIC-1 Order.

The Industrial Group argues that the net rate revenue attributable to rural extensions should be capped at $5.7 million, which is based on the cost estimates and margin forecasts used in TDSIC-1. However, the proposal we approved in TDSIC-1 was not based on any particular amount of net revenue that customers would pay or that NIPSCO would receive. To the contrary, the proposal we approved in TDSIC-1 established that NIPSCO will provide a credit equal to 80% of *actual* margins received from new rural customers. We approved this proposal because we found, and continue to find, that it will help encourage new rural extensions, which we conclude is an important aspect of the TDSIC Statute, and because the 80% margin credit will help offset the cost to existing customers.

Based on our review of the evidence, we find it is reasonable, appropriate, and consistent with sound regulatory policy for NIPSCO to continue to review the assumptions used to develop the expected number of rural extensions as well as the expected margin from new rural customers. Unlike other projects included in the 7-Year Gas Plan, the ultimate scope of the rural extensions project is not in NIPSCO's full control because customers have to choose to connect. In addition, the evidence shows the assumption for expected margins is important in determining whether a potential project will meet the 20-year test. It is reasonable for NIPSCO to review and update its assumptions and adjust the revenue forecast accordingly. Furthermore, we note these updated assumptions are used to forecast the cost estimate for the rural extensions project and to forecast the eventual margin credit to existing customers. However, only *actual* costs and *actual* margins will be included in the TDSIC. For these reasons, we conclude it is not appropriate to "cap" the net revenue impact of the rural extensions project.

The OUCC reiterated its argument from TDSIC-1 and recommended that the Commission require NIPSCO to use the 20% of margins from new rural customers retained by NIPSCO to offset the 20% of deferred costs in NIPSCO's next general rate case. We considered and rejected this recommendation in TDSIC-1, and we decline the OUCC's request to reconsider. We again note that the TDSIC Statute encourages utilities to make investments to serve new customers, but does not require a utility to provide a credit for margin received from new rural customers.

Based on the evidence of record, we conclude that the rural extensions margin credit calculated on Exhibit 1-A, Attachment 2, Schedule 5 of Petitioner's Exhibit 1 is computed in accordance with the TDSIC-1 Order, and it is approved.

4. Calculation of TDSIC Factors. Mr. Isensee sponsored Exhibit 1-A, Attachment 1, Corrected Schedule 7 of Petitioner's Exhibit 1, which shows the calculation of the TDSIC factors by rate code based on the total revenue requirement adjusted for prior period variances of $7,639,184 (at Line 7). 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 for the months of February through May 2016. Mr. Isensee sponsored Exhibit 1-A Corrected Attachment 3 to Petitioner's Exhibit 1 (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 months of February through May 2016, or until replaced by different factors that are approved in a subsequent proceeding.

The OUCC indicated that generally NIPSCO's TDSIC calculation schedules, Exhibit 1-A, Attachment 1, Schedules 1-9, and Attachment 2, Schedules 1-6 of Petitioner's Exhibit 1, effectively and accurately calculate and track TDSIC costs and rate factors based on NIPSCO's proposal.

Based on the evidence and our conclusions regarding the exclusion of certain new and emergent projects and the appropriate customer class revenue allocation factor, we approve the proposed TDSIC factor calculation methodology set forth in NIPSCO's Corrected Attachment 3 to be applicable to bills rendered during the months of March through May 2016 or until replaced by new factors. NIPSCO shall file a revised Schedule 7 reflecting the effects of the findings above on the proposed TDSIC factors.

5. Billing Period. In this proceeding, NIPSCO requests approval of TDSIC factors to be applicable to bills rendered during the billing months of February through May 2016 to effectuate the timely recovery of 80% of TDSIC costs incurred in connection with NIPSCO's eligible improvements. Mr. Isensee testified the TDSIC factors include TDSIC costs incurred through June 30, 2015. He further testified that NIPSCO agreed to a 150-day procedural schedule in this proceeding with an expected order date on or about January 27, 2016. Under the normal 90-day schedule, the factors would be effective for a six-month period from December 2015 through May 2016. With the extended 150-day schedule NIPSCO needed to shorten the period to four months in order to stay on the normal TDSIC filing schedule. He testified that the factors are designed to collect the entire revenue requirement over the four-month period and any differences will be reconciled in Cause No. 44403 TDSIC-5 ("TDSIC-5").

Mr. Grosskopf recommended that NIPSCO's next TDSIC petition should be filed in time to facilitate recovery of updated rates on June 1, 2016, or otherwise cease recovery of TDSIC-3 rates as of that date. He also recommended that in Cause No. 44403 TDSIC-4 ("TDSIC-4"), NIPSCO should be required to reconcile the TDSIC-1 revenue requirement with actual revenue collected during the six-month period of June through November 2015. In rebuttal, Mr. Caister testified that NIPSCO intends to file its TDSIC-4 proceeding on or before March 1, 2016 to return to a semi-annual filing cycle.

Due to the dismissal of TDSIC-2, NIPSCO continues to collect TDSIC-1 revenues, including the period of June 2015 through November 2015 based on the TDSIC-1 approved rates. In response to the Commission's December 3, 2015 docket entry, NIPSCO stated that in TDSIC-4, it will reconcile the months of June through November 2015. NIPSCO will reconcile the TDSIC factor revenue from December 2015 through May 2016 in TDSIC-5. Consistent with the approved Motion to Dismiss in TDSIC-2, NIPSCO included the costs that would have been recovered in conjunction with TDSIC-2 (TDSIC costs incurred through June 30, 2015) in the TDSIC-3 factors. These costs will be reconciled as part of TDSIC-5.

Based on the reconciliation process approved in TDSIC-1 and Mr. Isenee's testimony explicitly stating the TDSIC-3 revenue requirement will be reconciled in TDSIC-5, we decline to adopt Mr. Grosskopf's recommendation to cease recovery of TDSIC-3 factors in the event that new TDSIC-4 factors are not approved and implemented by June 1, 2016. We also note that this is procedurally consistent with how the recovery period was handled in TDSIC-1, which also had a 150-day procedural schedule.

E. <u>Deferred TDSIC Costs</u>. In the TDSIC-1 Order, we authorized NIPSCO to defer 20% of the TDSIC costs incurred in connection with its eligible improvements and recover those deferred costs in its next general rate case. TDSIC-1 Order at 30. NIPSCO was also authorized to record ongoing carrying charges based on the current overall WACC on all deferred TDSIC costs until such costs are recovered in NIPSCO's base rates as a result of its next general rate case. *Id.* We also authorized NIPSCO to defer all approved 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. *Id.*

In this proceeding, Mr. Isensee sponsored Exhibit 1-A, Attachment 1, Corrected Schedule 9 of Petitioner's Exhibit 1 which shows 20% of the total revenue requirements calculated in Exhibit 1-A, Attachment 1, Corrected Schedule 5 of Petitioner's Exhibit 1. He testified the amount included in Column F represents the ongoing carrying charges, based on NIPSCO's WACC, on all deferred TDSIC costs incurred through June 30, 2015. He stated these costs will be included for recovery in NIPSCO's base rates in its next general rate case.

In the TDSIC-1 Order, we also ordered that with respect to the 112th Street project, NIPSCO may recover a return on its investment and the related depreciation expense, property taxes, and carrying charges associated with the best estimate provided by NIPSCO in Cause No. 44403 and NIPSCO may defer for recovery in its next base rate case the difference between the amount authorized in Cause No. 44403 and the actual cost of the project. Consistent with the TDSIC-1 Order, NIPSCO proposes to defer for recovery in its next base rate case the depreciation expense and property taxes related to the difference between the amount approved in Cause No. 44403 and the actual amount of the project. Mr. Isensee sponsored Exhibit 1-A, Attachment 1, Schedule 10 of Petitioner's Exhibit 1, which shows the total depreciation and property taxes NIPSCO proposes to defer relating to this difference as of June 30, 2015.

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 $2,117,078 and $58,718 (Attachment 1, Schedule 10, Line 13) in accordance with our TDSIC-1 Order.

F. <u>Average Aggregate Increase in Total Retail Revenues</u>. Ind. Code § 8-1-39-14(a) states as follows:

> 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 Exhibit 1-A, Attachment 1, Corrected Schedule 8 of Petitioner's Exhibit 1, 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 TDSIC-1 Order, 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, 2015 time period. Based on this evidence, we find that NIPSCO's proposed TDSIC-3 factors as adjusted herein will not result in an average aggregate increase in NIPSCO's total retail revenues of more than 2% in a 12-month period.

6. <u>Confidential Information</u>. NIPSCO filed a motion for protective order on August 31, 2015, 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 22, 2015, 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's Plan Update-3 is approved as modified in this Order, and the approved projects are designated as eligible transmission, distribution, and storage system improvements under Ind. Code § 8-1-39-2.

2. NIPSCO is authorized to defer and recover 80% of the approved TDSIC costs incurred in connection with the eligible transmission, distribution, and storage improvements approved in this Order in its rates and charges for gas service in accordance with NIPSCO's TDSIC beginning with the month of March 2016.

3. 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).

4. NIPSCO is authorized to defer, as a regulatory asset, 20% of the TDSIC costs incurred in connection with the eligible transmission, distribution, and storage improvements approved in this Order and recover those deferred costs in its next general rate case, which is to be filed no later than April 30, 2021.

5. NIPSCO is authorized to record ongoing carrying charges based on the current overall WACC on all deferred TDSIC costs until such costs are recovered in NIPSCO's base rates as a result of its next general rate case.

6. NIPSCO is authorized to defer, as a regulatory asset, for recovery in NIPSCO's next general rate case depreciation expenses and property tax expenses associated with the difference between the amount authorized for the 112th Street project in Cause No. 44403 and the actual cost of the project as approved in this Order.

7. Prior to implementing the authorized TDSIC factors, NIPSCO shall file the applicable rate schedules under this Cause for approval by the Commission's Energy Division.

8. 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 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.

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

STEPHAN, MAYS-MEDLEY, WEBER, AND ZIEGNER CONCUR; HUSTON ABSENT:

APPROVED: MAR 30 2016

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

Shala M. Coe

Shala M. Coe
Acting Secretary to the Commission