FILED
May 22, 2020
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC FOR APPROVAL OF PETITIONER'S TDSIC PLAN FOR ELIGIBLE TRANSMISSION, DISTRIBUTION, AND STORAGE SYSTEM IMPROVEMENTS, PURSUANT TO IND. CODE § 8-1-39-10(a) INCLUDING TARGETED ECONOMIC DEVELOPMENT PROJECTS PURSUANT TO IND. CODE § 8-1-39-10(c) AND EXTENSIONS TO RURAL AREAS PURSUANT TO IND. CODE § 8-1-39-11, FOR AUTHORITY TO DEFER COSTS FOR FUTURE RECOVERY AND APPROVING INCLUSION OF NIPSCO'S TDSIC PLAN PROJECTS IN ITS RATE BASE IN ITS NEXT GENERAL RATE PROCEEDING PURSUANT TO IND. CODE § 8-1-2-23.	)	CAUSE NO. 45330 APPROVED:

NIPSCO INDUSTRIAL GROUP'S

EXCEPTIONS TO NIPSCO'S PROPOSED ORDER

Intervenor, NIPSCO Industrial Group ("Industrial Group"), by counsel, submits its exceptions to NIPSCO's proposed order as outlined herein.

The NIPSCO Industrial Group provides a revised Para. 6 summarizing its testimony and objects to the entirety of Paras. 8(D) and 8(I)(i)-(iii) of NIPSCO's Proposed Order and submits in its place a new discussion and findings for those sections. The Industrial Group's proposed inserts are attached hereto as Exhibit "A".

In the attached Exhibit "B", the Industrial Group submits a redline version of NIPSCO's proposed order. A clean Word version of Exhibit B will be provided to the Administrative Law Judge and counsel of record.

The Industrial Group is also submitting a supporting brief as a separate document. To the extent that this submission or the supporting brief do not expressly address any additional issues raised in this proceeding, the absence of discussion should not be construed as an endorsement of or acquiescence in the position taken by any other party.

Respectfully submitted,

LEWIS & KAPPES, P.C.

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing has been served upon the following via electronic mail, this 22nd day of May, 2020:

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EXHIBIT A

Exhibit A

Paragraph 6 Insert (Replacing Para. 6)

6. **<u>Industrial Group's Case-in-Chief</u>.** Mr. Phillips testified to the relevant background and history of NIPSCO's gas system and rate proceedings over the past 35 years. Mr. Phillips discussed the 22-year period between the 1988 and 2010 rate cases. Mr. Phillips stated that NIPSCO's depreciation rates were set at a high level in 1988, but NIPSCO did not perform any substantial system investments over that time, which resulted in a reduction in NIPSCO's rate base from $719 million in 1988 to $318 million in 2010. Because NIPSCO's rate base had fallen so much, the settlement that resolved the 2010 rate case provided for a fair value rate base of $726 million instead of book value and implemented a depreciation credit that would allow NIPSCO to better reflect the useful lives of system assets.

He discussed NIPSCO's first TDSIC plan, which was approved on April 30, 2014. That Plan approved cost estimates of $713 million, consisting of $593 million in direct capital and $120 million in indirect capital and AFUDC. The Plan focused on seven major long-needed projects to NIPSCO's high-pressure transmission system. However, less than a year and a half later, NIPSCO announced substantial delays affecting several of the major transmission projects, two of which were removed from the Plan in their entirety. At the same time, the estimated costs for the seven major transmission projects increased by nearly 60%. Despite the removal of the two of the seven major transmission projects and postponing other substantial work beyond the Plan period, the estimated costs of the Plan increased to $817 million, consisting of $677 million in direct capital and $140 million in indirect capital and AFUDC.

When NIPSCO filed its next rate case in 2017, Mr. Phillips described how NIPSCO's original cost rate base had increased to almost $1.5 billion, largely as a result of the TDSIC capital investment combined with the depreciation credit from the 2010 rate case settlement. The 2017 rate case also resulted in a settlement, which reduced the rate impact on large volume customers from a 70% increase to a still dramatic 39%.

Mr. Phillips discussed how, after the 2017 rate case was settled, the TDSIC plan had increased to $850 million in total capital. Following a remand from the Indiana Supreme Court, NIPSCO reduced total capital to $680 million through a settlement approved in the TDSIC-9 proceeding. That settlement also established cost caps on recoverable costs through the remaining two years of the original Plan, which was scheduled to terminate at the end of 2020. However, at the end of 2019, NIPSCO terminated the original Plan and filed this proceeding.

Mr. Phillips stated that NIPSCO's proposed Plan seeks approval of $948.7 million in total capital, with nearly half the planned work relating to two of the original seven major transmission projects that were proposed in the first Plan but were not completed. Another quarter of the proposed Plan consists of rural extensions, but NIPSCO confirmed that it would continue the 80% margin credit that had been used in the prior Plan. With respect to the total capital, compared to the original plan, which involved $679.8 million over a seven-year period, or $97.1 million per year, the proposed plan over a six-year period would average $158.1 million annually, or about 63% higher than under the prior Plan.

With respect to the two major transmission projects that were also proposed in the prior Plan, Mr. Phillips discussed how in the six years from first being proposed, the cost estimates have increased 445%. Mr. Phillips stated that lack of system investment in the period after the 1988 rate case also contributed to a $474.4 million decrease in system value by 2010. Mr. Phillips stated that if NIPSCO had undertaken those improvements at an earlier point, they could have been completed at a fraction of the cost now proposed. Mr. Phillips stated that NIPSCO provided no good reason why the work could not have been performed much earlier at a much lower cost, instead of delaying the work until the budgets inflated so drastically. Further, Mr. Phillips stated that the risks that NIPSCO identifies now as the justification for the projects have been present and apparent for many years. Mr. Phillips stated that despite the Aetna to 483# Loop being the highest priority project in the original TDSIC Plan, NIPSCO still has not completed that project and customers are still several years away from seeing the benefits.

Mr. Phillips also discussed the rate implications of the proposed TDSIC Plan as a tracked expense, as well as for a future base rate case. In this case, Mr. Phillips stated that NIPSCO projects to recover $53.4 million annually through the TDSIC tracker, not including the 20% deferred to the next rate case. By the time of NIPSCO's next rate case, Mr. Phillips stated that NIPSCO's book value of its plant will increase another billion dollars, an increase of seven or eight times what it was in 2010. This will lead to another massive rate increase for ratepayers.

Despite this history, Mr. Phillips recommended the system work that NIPSCO plans to perform would provide operational benefits and should be completed. However, Mr. Phillips recommended close scrutiny of the cost estimates to prevent ratepayers from bearing excessive cost responsibility and further protections to mitigate the rate impacts, both in upcoming tracker proceedings as well as in NIPSCO's next rate case.

Mr. Phillips stated there are three components in particular that are excessive or unnecessary: (1) the contingencies in the estimates, (2) the escalation factor, and (3) the proposed indirect capital and AFUDC.

Mr. Phillips testified that the contingency allowance proposed by NIPSCO is unnecessary and should be disallowed. Mr. Phillips stated that the estimated costs for the two main transmission projects have already increased by 445% above what NIPSCO presented as its best estimate six years ago in Cause No. 44403. That increase dwarfs the proposed contingency requested by NIPSCO, and consequently any further risk should be borne by NIPSCO and not ratepayers. He stated that instead of preapproving contingencies for automatic recovery in rates, the Commission should apply the specific justification standard under the TDSIC Statute in the event of further unanticipated cost increases. Mr. Phillips testified that the statutory process places the burden on NIPSCO to justify any excess costs and leaves the risk with NIPSCO to manage any contingencies that may not meet the specific justification standard.

Mr. Phillips testified that NIPSCO's 3% escalation factor should be reduced to 2%, to reflect the Federal Reserve's targeted 2% long-term inflation rate. He testified that the Commission recently found that a proposed escalation factor of 2.25% was excessive in Cause No. 45235, and that 2.1% was more consistent with the long-range outlook of the Federal Reserve and consensus economists. Like contingency, he stated that cost estimates approved by the Commission that include an inflation adjustment amount to preapproval of automatic increases under the TDSIC Statute and shifts additional risk to ratepayers and reduces NIPSCO's incentive to complete the work as cost-effectively as possible. The TDSIC statute provides a mechanism for NIPSCO to seek specific approval for resulting cost increases. Mr. Phillips stated that this was especially appropriate given that the hundreds of millions of dollars of additional cost were due to NIPSCO's delay in completing the work.

Mr. Phillips stated the projected levels of $109 million of indirect capital and $32.1 million of AFUDC are excessive and higher than actual experience in the past 5 years. Indirect capital and AFUDC are applied by NIPSCO as percentages to the direct capital spend. Although NIPSCO stated that its proposed indirect capital and AFUDC percentages of 13.5% and 3.5%, respectively, reflected NIPSCO's experience with the prior Plan, the most recent 5-year period average for indirect capital was 10.94% and for AFUDC was 2.5%. Mr. Phillips testified that the proposed use of the higher percentages would result in excessive costs in the Plan estimates, and would unnecessarily increase the amounts preapproved for recovery through rates. Mr. Phillips stated that percentages for indirect capital and AFUDC for 2014 were not included in the average because they were an outlier and not calculated using the General Ledger software implemented by NIPSCO starting in 2015. Mr. Phillips testified that similar to contingency and cost escalation, the TDSIC statutory mechanism provides a balanced approach that requires NIPSCO to provide substantial justification before rate responsibility for any increases is placed on customers, which gives NIPSCO a strong incentive to complete the work on budget.

Mr. Phillips stated the pretax return assumed by NIPSCO in its rate calculations is based on the return authorized in its last rate case, which is higher than appropriate in this context. He testified that the pretax return for TDSIC purposes should be significantly lower, to reflect the reduction in risk arising from preapproved rate recovery for rate base investments. In addition, he stated that the allowed return for TDSIC purposes should recognize that NIPSCO proposes to continue to collect return in base rates associated with removed assets while also adding incremental return under the TDSIC tracker for replacement assets performing the same functions. He noted that a prior appellate decision noted that the statute did not require netting, but that the Commission could consider the impact of duplicative recovery in determining the appropriate pretax return. Mr. Phillips recommended that the Commission should make a downward adjustment to the approved pretax return. Mr. Phillips stated that the approved 9.85% return on equity was excessive in the context of the continued recovery of replaced assets and in light of the significant risk reduction due to NIPSCO's tracking of major investments and expenses, such as its gas cost and other federally mandated costs. Unlike electric utilities, Mr. Phillips stated that gas utilities do not require major investments in production plant.

Paragraph 8(D) Insert (Replacing Para. 8(D))

D. <u>Best Estimate of Costs</u>. Ind. Code § 8-1-39-10(b)(l) requires that the Commission's order on a TDSIC Plan must include "[a] finding of the best estimate of the cost of the eligible improvements included in the plan."

NIPSCO's TDSIC Plan proposes six years of defined investment totaling $807,573,279 in direct capital and an additional $141,103,241 in indirect capital and AFUDC, for a total of $948,676,520. The estimated Plan direct capital cost addresses $92,656,660 (11%) of gas system deliverability projects, such as adding new gas mains and adding or upgrading regulator stations to improve NIPSCO's ability to meet customers' deliverability demands; $531,495,088 (66%) of gas system integrity projects, such as replacing certain segments of NIPSCO's gas transmission, distribution, and storage facilities to ensure public safety, and asset replacements identified to be at risk of continued operability through routine and special inspection and assessment cycles; and $183,421,531 (23%) of rural gas extension projects making investments in new or upgraded gas mains and / or regulator stations, and new services to make natural gas available to rural customers. The total direct capital cost estimate is $598,060,860 transmission cost; $193,896,775 distribution costs; and $15,615,644 storage costs. NIPSCO's TDSIC Plan provides year-by-year project details, including cost estimates in a sortable list and an associated summary of the Plan's cost by FERC account (TDSIC Plan, Page 2).

NIPSCO developed cost estimates for the projects included in the TDSIC Plan using the AACE Cost Classification System. The confidential appendices included in NIPSCO's TDSIC Plan included a risk register, asset registers, project estimates, and unit cost estimates. Further, as part of its periodic update process, NIPSCO plans to update the Plan and include information regarding its cost estimates by project for each calendar year. In accordance with Ind. Code § 8-1-39-9(g), any costs in excess of approved expenditures and costs will be subject to review under the specific justification standard before being authorized for recovery in rates. NIPSCO will provide PCR forms to support material project estimate changes during the current year for projects. Actual costs (direct capital, indirect capital, and AFUDC) will be included in the Plan update when a given calendar year is closed out. Rural extension inputs will be updated annually.

Although NIPSCO's estimates are based on the AACE Cost Classification System, we echo Mr. Phillips' concerns with the increase NIPSCO has proposed with respect to the two major transmission projects that were originally proposed in NIPSCO's prior TDSIC Plan. Based on the 445% increase in those two major projects, which combine for almost half of the entire 6-year TDSIC spend, Mr. Phillips recommended that the contingency included in NIPSCO's cost estimates is unnecessary and should be disallowed. Instead of including contingency in NIPSCO's best estimate, Mr. Phillips recommended that the Commission focus on the Section 9 requirements of the TDSIC statute, and that in future tracker proceedings, NIPSCO demonstrate specific justification if there is a need to increase the cost estimates from the amounts approved in this proceeding. In light of the massive cost increases, we find that inclusion of additional contingency, which are established from the increased base cost of the projects, would unreasonably shift the burden to maintain cost control from NIPSCO to ratepayers. Any further increases to NIPSCO's cost estimates should be made in the context of the tracker proceeding in which NIPSCO will need to demonstrate specific justification for the increase. Given these considerations, we find the exclusion of contingency from the cost estimate is appropriate and will not be included in the best cost estimate as required by the TDSIC Statute.

Industrial Group witness Mr. Phillips and OUCC witness Mr. Krieger also recommended that NIPSCO's escalation rate should be reduced to 2%, which is the current target inflation rate of the Federal Reserve. While Mr. Bull attempted to differentiate our approval of a reduced 2.1% escalation factor in the context of a decommissioning cost estimate discussed in Cause No. 45235, we note that decommissioning projects, like gas construction projects, are utility capital projects that involve material, labor, and supplies. We see no reason to further increase cost escalation beyond the Federal Reserve target inflation rate. Again, as noted above, NIPSCO has the opportunity to demonstrate specific justification for increases beyond the approved 2% escalation, which is already subject to compounding over the six-year term of the Plan. Given these considerations, we find the reduction of escalation to 2% in the cost estimate is appropriate and would establish the best cost estimate as required by the TDSIC Statute.

Regarding indirect capital cost and AFUDC, Industrial Group witness Mr. Phillips suggested that it would be more reasonable to calculate indirect capital at the most recent 5-year period average of 10.94% and AFUDC at the most recent 5-year period average of 2.5%. In contrast, NIPSCO proposed percentages that are higher than any of the actual figures used by NIPSCO in any of the past five years, indicating that it relied on increased indirect capital costs for 2019 and forward looking estimates from NiSource's Financial Planning and Analysis department, and further increasing AFUDC to 3.5% to account for the large multi-year gas transmission projects. We find that the historic average approach provides a reasonable reflection of projected indirect costs and AFUDC, and that NIPSCO's higher proposal has not been supported with quantifiable and reliable data. Accordingly, we find that NIPSCO's estimates of indirect capital and AFUDC should be limited to the historic five-year average of 10.94% and 2.5%, respectively.

Based on the evidence presented, we find that the record demonstrates that the estimated cost of NIPSCO's TDSIC Plan should include only the base project cost, without additional contingency allowance, subject to an escalation factor of 2.0%, and indirect capital cost and AFUDC limited to 10.94% and 2.5% respectively, which rests on a sound factual and analytical foundation and is reasonable. Accordingly, we find the best estimate of the cost of the eligible improvements included in the Plan is the resulting amount based on the findings herein.

Paragraphs 8(I)(i) and (ii) Insert (Replacing Paragraphs 8(I)(i)-(iii))

i. Calculation of Indirect Capital Costs and AFUDC. As set forth above, we find that indirect capital shall be limited to 10.94% of the capital cost, and AFUDC shall be limited to 2.5% of capital cost.

ii. Determination of Pretax Return. OUCC witness Mr. Grosskopf recommended that in a future tracker filing the Commission should consider adjustments to the WACC proposed by NIPSCO when determining the pretax return to be used for TDSIC purposes. Industrial Group witness Mr. Phillips recommended that the pretax return for TDSIC purposes should be significantly lower, to reflect the reduction in risk arising from preapproved rate recovery for rate base investments. Mr. Phillips stated that the allowed return for TDSIC purposes should recognize that NIPSCO proposes to continue to collect return in base rates associated with removed assets while also adding incremental return under the TDSIC tracker for replacement assets performing the same functions.

In a 2015 appellate decision reviewing the order in Cause No. 44371, the Court of Appeals addressed the issue of duplicative recovery under the TDSIC mechanism with respect to replaced assets. *See NIPSCO Indus. Grp. v. N Ind Pub. Serv. Co.*, 31 N.E.3d 1, 10-13 (Ind. Ct. App. 2015). While indicating that the issue raised "significant concerns," the Court concluded that the TDSIC statute did not expressly require "netting" of return to reduce the costs subject to TDSIC recovery. *Id.* at 13. At the same time, however, the Court pointed out that Ind. Code §8-1-39-13 authorizes the Commission to consider "other information" when determining a pretax return for TDSIC purposes, and indicated that provision would be an appropriate avenue to address the issue. *Id.* at 12 ("The statute does, however, allow the Commission to consider '[o]ther information that the commission determines is necessary' in calculating pretax returns.") (*citing* Ind. Code § 8-1-39-13); *id.* at 13 ("The Commission could, under this statute, address the OUCC's concern, however, it is not *required* to do so.") (emphasis in original).

NIPSCO, in its proposed order in this case, cited our discussion in Cause No. 44371 in support of its positon that no adjustment to its WACC was necessary. However, in making its argument, it failed to note the subsequent history of the appeal. The Court of Appeals, in reversing the Commission's Order in Cause No. 44371, agreed that while the TDSIC statute does not require netting, the statutory language supports the position taken by the Industrial Group here: that if the Commission chooses not to support netting of replaced assets, an adjustment to the pretax return of the utility would be appropriate.

Further, in Cause No. 45264, the Commission noted that modifications to the authorized return on equity would be appropriate for consideration in IPL's first TDSIC tracker proceeding. *IPL*, Cause No. 45264 at 27 (IURC March 4, 2020):

> Although we have consistently concluded that the TDSIC statute does not allow for the netting of retired assets as advocated by the OUCC, we note that we also found in our February 17, 2014 Order in Cause No. 44371, at p. 17, that the TDSIC statute "does not preclude us from increasing or decreasing the allowed return on equity [which is used in determining the utility's weighted average cost of capital], as the Commission is authorized to consider other necessary information in determin[ing] the appropriate pretax return." Based on the passage of time and the experience we have gained implementing the TDSIC statute over the past six years, as well as the OUCC's continued concerns with double recovery and the Industrial Group's concerns with the shifting of risks based on plan approval, we find it appropriate to explore a reasonable adjustment under the statutory provisions.

Id.

Like IPL, NIPSCO had a recent base rate proceeding. However, given the concerns raised with double counting plant recovery and the overall risk reduction provided by statutory mechanisms on substantial TDSIC investments, as well as other tracked expenses, we find that reasonable adjustments to NIPSCO's approved WACC shall be considered in the first TDSIC tracker proceeding following approval of this Order.

EXHIBIT B

Exhibit B

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC FOR APPROVAL OF PETITIONER'S TDSIC PLAN FOR ELIGIBLE TRANSMISSION, DISTRIBUTION, AND STORAGE SYSTEM IMPROVEMENTS, PURSUANT TO IND. CODE § 8-1-39-10(a) INCLUDING TARGETED ECONOMIC DEVELOPMENT PROJECTS PURSUANT TO IND. CODE § 8-1-39-10(c) AND EXTENSIONS TO RURAL AREAS PURSUANT TO IND. CODE § 8-1-39-11, FOR AUTHORITY TO DEFER COSTS FOR FUTURE RECOVERY AND APPROVING INCLUSION OF NIPSCO'S TDSIC PLAN PROJECTS IN ITS RATE BASE IN ITS NEXT GENERAL RATE PROCEEDING PURSUANT TO IND. CODE § 8-1-2-23.	)	**CAUSE NO. 45330** **APPROVED:**

ORDER OF THE COMMISSION

Presiding Officers:
Sarah E. Freeman, Commissioner
Lora L. Manion, Administrative Law Judge

On December 31, 2019, Northern Indiana Public Service Company LLC ("NIPSCO" or "Petitioner") filed its Verified Petition, together with its testimony and exhibits constituting its Case-In-Chief, seeking Indiana Utility Regulatory Commission ("Commission") approval of its plan for eligible transmission, distribution and storage system improvements, pursuant to Ind. Code § 8-1-39-10(a), including targeted economic development projects, pursuant to Ind. Code § 8-1-39-10(c) and extensions to rural areas, pursuant to Ind. Code § 8-1-39-11 ("2020-2025 Gas Plan," "TDSIC Plan," or "Plan"). The following witnesses provided testimony in support of NIPSCO's case-in-chief:

- Alison M. Becker, NIPSCO Manager of Regulatory Policy
- Donald L. Bull, NIPSCO Director of Gas TDSIC Projects
- James F. Racher, NiSource Corporate Services Company Director of Regulatory
- Adam S. Wittorp, NIPSCO Manager of Gas Control

On December 31, 2019, NIPSCO also filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information, which the Commission granted on a preliminary basis in its January 16, 2020 docket entry.

NIPSCO Industrial Group ("Industrial Group") and Steuben County Economic Development Corporation ("SCEDC") filed petitions to intervene, both of which were subsequently granted.[1]

On April 9, 2020, the Indiana Office of Utility Consumer Counselor ("OUCC"), Industrial Group and SCEDC filed their respective testimony and attachments. The OUCC filed testimony from the following witnesses:

- Brien R. Krieger, Utility Analyst in the Natural Gas Division; and
- Mark H. Grosskopf, Senior Utility Analyst in the Natural Gas Division.

The Industrial Group filed testimony from Nicholas Phillips, Jr., Principal, Brubaker & Associates, Inc. as well as a Motion for Administrative Notice, which is hereby granted. ~~[DID COMMISSION RULE?]~~

SCEDC filed testimony from Isaac R. Lee, Executive Director of the SCEDC.[2]

On April 14, 2020, NIPSCO filed an Objection and Motion to Strike portions of Mr. Lee's testimony, to which SCEDC responded on August 24, 2020. NIPSCO replied to SCEDC's response on May 1, 2020. The Presiding Officers granted NIPSCO's motion by Docket Entry dated May 4, 2020.

On April 22, 2020, NIPSCO filed rebuttal testimony and attachments of Mr. Bull and Mr. Racher.

On May 5, 2020, the Presiding Officers issued a docket entry requesting NIPSCO to provide additional information, to which NIPSCO responded on May 6, 2020.

The Commission noticed this matter for an evidentiary hearing at 9:30 a.m. on May 12, 2020, in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. A Docket Entry was issued on May 8, 2020, advising that in accordance with the Indiana Governor Holcomb's Executive Order 20-09, the hearing would be conducted via teleconference and providing related information. NIPSCO, the OUCC, the Industrial Group, and SCEDC, by counsel, participated in the evidentiary hearing via teleconference, and the testimony and exhibits of NIPSCO, the OUCC, and the Industrial Group, including the Industrial Group's administrative notice documents, ~~-~~were admitted into the record without objection.

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

1. <u>Notice and Jurisdiction</u>. Notice of the hearing in this Cause was given and published by the Commission as required by law. NIPSCO is a public utility as that term is defined in Ind. Code § 8-1-2-1(a). Under Ind. Code §§ 8-1-39-10 and -11, the Commission has jurisdiction

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1 The members of the Industrial Group in this proceeding are ArcelorMittal USA, BP Products North America, Inc., Praxair, Inc., United States Steel Corporation, and USG Corporation.

2 SCEDC filed testimony and exhibits of Isaac R. Lee, Executive Director of SCEDC that was not offered into evidence.

over a public utility's plan for eligible transmission, distribution, and storage improvements, including targeted economic development projects and extension of gas service in rural areas. Therefore, the Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

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

3. **Requested Relief.** NIPSCO requests approval of its TDSIC Plan pursuant to Ind. Code § 8-1-39-10(a), including targeted economic development projects, pursuant to Ind. Code § 8-1-39-10(c) and extensions to rural areas, pursuant to Ind. Code § 8-1-39-11. NIPSCO's TDSIC Plan proposes six years of defined investment totaling $807,573,279 as follows:

Investment Segment	2020-2025 Gas Plan Projected Investment (Direct Capital Dollars)
Gas System Deliverability	$92,656,660
Gas System Integrity	$531,495,088
Rural Gas Extensions	$183,421,531
Plan Total	**$807,573,279**

4. **NIPSCO's Case-in-Chief.**

A. **Overview.** Mr. Bull explained that NIPSCO's TDSIC Plan is focused on gas transmission, distribution, and storage system investments made for safety, reliability, system modernization, or economic development. Mr. Bull testified the total estimated capital cost of the 2020-2025 Gas Plan is $948,676,520, including direct capital ($807,573,279), indirect capital ($109,022,393) and allowance for funds used during construction ("AFUDC") ($32,080,848), and he identified the Plan costs by year. The 2020-2025 Gas Plan includes a Transmission Risk Comparison (Confidential Appendix 1) used to identify and prioritize the transmission pipeline replacement projects, project estimates (Confidential Appendix 2), and a summary of unit cost estimates (Confidential Appendix 3), used to support the cost estimates associated with the capital improvement projects included in the Plan. Mr. Bull described that the Plan is comprised of three segments: (1) investments aimed at maintaining the system reliability through the capacity of the system to deliver gas to customers when they need it (Gas System Deliverability); (2) replacement of certain system assets to ensure the ongoing integrity and safe operation of the gas system (Gas System Integrity); and (3) the extension of gas facilities into rural areas (Rural Gas Extensions). Mr. Bull provided a description of each of the investment segments. He stated the Plan allows NIPSCO to make necessary investments to continue providing safe, reliable gas service to its customers into the future.

B. **TDSIC Plan.** Mr. Bull explained that the assets reviewed as part of the

2020-2025 Gas Plan included all current transmission, distribution, and storage system assets at NIPSCO. He testified that NIPSCO engaged EN Engineering to work with its engineering, planning, and system integrity teams to review NIPSCO's gas transmission and distribution strategies during the development of Gas Plan 1 and continued that relationship in the preparation of the 2020-2025 Gas Plan. He stated the Transmission Risk Comparison prepared by EN Engineering dated November 26, 2019 (the "Risk Model"), along with internal subject matter expert input, was used in development of the 2020-2025 Gas Plan.

Mr. Bull explained that the Risk Model (attached to the 2020-2025 Gas Plan as Confidential Appendix 1) shows the impact that the projects NIPSCO completed in Gas Plan 1 had and the projects NIPSCO anticipates completing in the 2020-2025 Gas Plan will have on reducing overall risk. Mr. Bull provided an overview of the methodology used by EN Engineering in evaluating risk. He stated the engineering analysis for individual projects incorporated specific algorithms and ranking methodologies (identified in Appendix A to Confidential Appendix 1 to the Plan). He testified this methodology is consistent with the risk ranking methodology used in support of NIPSCO's Gas Plan 1 and is also generally consistent with other risk ranking approaches with which he is familiar. He explained that relative risk is always a function of the likelihood of occurrence and the potential consequence associated with a specific event, and is a logical way to approach the prioritization of risks when faced with practical considerations that limit the ability to address all risks simultaneously.

Mr. Bull testified the 2020-2025 Gas Plan was developed to address risks identified and prioritized as of early 2019, and as such, the 2020-2025 Gas Plan represents the current best path forward to ensure the continued delivery of safe and reliable gas service to NIPSCO's customers. He explained that in considering the Plan design, NIPSCO conducted comprehensive reviews of many segments of its gas system. He stated the Plan addresses high priority safety, operational and integrity needs, and extends gas facilities into rural areas. He explained that projects were also reviewed to provide a high level of confidence that they could be executed as proposed and that a broader portfolio of projects was prioritized to develop the specific improvements included in the Plan.

Mr. Bull described the reduction in risk through completion of the project in Gas Plan 1 and testified the transmission projects included in the 2020-2025 Gas Plan result in further risk reduction. He added that, based on the Risk Model, upon completion of the transmission projects in the 2020-2025 Gas Plan a total transmission system reduction of 32.5% from the 2013 baseline is forecasted.

Mr. Bull testified the transmission, distribution, and storage system investments included in the 2020-2025 Gas Plan are required for the public's convenience and necessity, address safety, reliability, system modernization, and economic development concerns, and provides incremental benefits for NIPSCO's customers.

C. <u>Best Estimate</u>. Mr. Bull testified the 2020-2025 Gas Plan includes projects that are similar to work NIPSCO performed as part of its Gas Plan 1. He explained that NIPSCO utilized PFES, LLC ("PFES"), a consulting, engineering and construction management firm that provides a broad range of professional services to the energy industry, to complete detailed cost estimates, followed by internal stakeholder reviews of those estimates. Mr. Bull stated that

NIPSCO gained significant experience with respect to the costs necessary for project completion, and cost estimates for this work reflect NIPSCO's experience on a range of the Gas Plan 1 projects of different types.

Mr. Bull described the approach PFES used for estimate development and the described the process PFES generally followed designed to align contributors with a detailed process for developing, reviewing, revising, and approving the planning, scope, and design of the project. PFES (1) developed cost estimates and documented work scopes and risks for projects identified by NIPSCO; (2) worked with NIPSCO to incorporate both the lessons learned from Gas Plan 1 and industry best practices when developing, reviewing, revising and finalizing project cost estimates; and (3) considered risks and opportunities identified during design reviews and field site visits which were incorporated into a risk matrix. He explained that existing scope and design documents were gathered and a site walk-down was typically completed with relevant internal stakeholders, a working session with the internal stakeholders was held to review and gather additional design basis information, a scope of work and a preliminary estimate was then developed and peer checked with other PFES employees and internal stakeholders. He stated this cycle of collecting data, completing or updating estimates, and completing reviews was repeated until a final formal review was completed after internal stakeholders were confident that the potential costs had been considered, and the final estimate was then accepted by NIPSCO.

Mr. Bull testified that the base estimates for three of the transmission pipeline replacement projects (TP8, TP10, and TP11) were updated by NIPSCO because the project maturity has increased since the initial estimates were prepared. NIPSCO also updated most of the estimates for the Inspect & Mitigate projects that are planned for execution in 2020. He noted that NIPSCO will update estimates for projects planned for execution later in the Plan as engineering progresses and will consider the costs associated with similar construction projects as part of those updates.

Mr. Bull testified that NIPSCO followed a rigorous project development, cost estimating, and review process to provide its best estimate for each project included in the Plan. Mr. Bull provided further detail about the estimation process for each of the projects included in the Plan.

As summarized in the Plan and discussed by Mr. Bull, the cost estimates provided in the 2020-2025 Gas Plan represent NIPSCO's best estimate of the cost of the eligible transmission, distribution, and storage system improvements. He stated that PFES performed detailed cost estimates for all projects that are not typically performed by NIPSCO, including all large transmission pipe segment replacements and storage projects. He explained that for the Aetna to Tassinong (Project ID TP10) and the Aetna to 483# Loop (Project ID TP11) projects, NIPSCO updated the PFES estimates as additional engineering was completed or other studies and reviews provided more specific information. He noted that for those projects that NIPSCO performs on a more routine basis, the estimates include a combination of estimates prepared by NIPSCO and PFES. For these reasons, Mr. Bull testified that NIPSCO's estimates of the costs of the eligible transmission, distribution, and storage system improvements included in its proposed the 2020-2025 Gas Plan are the best estimates of the project identified in the Plan.

Mr. Bull testified NIPSCO included contingency consistent with the AACE International ("AACE") Recommended Practice for cost estimate classification. He stated the AACE Recommended Practice is based on project maturity or progress of project engineering or project development. He explained the preliminary engineering for most projects in the 2020-2025 Gas Plan would support a Class 4 estimate based on the application of recent construction experience, added efforts to inspect and understand site conditions, identify real estate and environmental requirements, and characterize the project risks, especially on the larger transmission projects. Mr. Bull sponsored Confidential Attachment 2-C showing the contingency amount for each of the projects and testified the total contingency is about 9% of the 6-year Plan total direct capital costs (excluding contingency).

Mr. Bull testified that contingency is added to a project base cost estimate to cover uncertainty and project risk, which is critical to creating a realistic estimate of the final project cost and increases the transparency around the expected cost at completion for a project. He explained that because projects are developed through a process of progressive elaboration whereby details to complete the scope required to satisfy the project deliverables are developed through an iterative process over time, projects are generally not fully engineered or bid at the time the cost estimates are developed. He described that contingency is added for several reasons, including but not limited to: (1) covering details that may be identified later in the iterative design process; (2) covering requirements that may not have been reasonably anticipated during the land acquisition or permitting process; (3) addressing responses or exceptions that may not have been reasonably anticipated during the bid process; or (4) accounting for field conditions where it is neither possible nor reasonable to identify all construction risks that could be encountered.

Mr. Bull explained how NIPSCO determined the contingency for the projects included in the Plan. He stated the contingency covers both potential changes in scope as additional engineering or design work is completed, uncertainty in cost estimates, and risks encountered during execution (including known risks that may be encountered, but not with a level of certainty that would warrant inclusion in the cost estimate), and to cover unknown risks that cannot be reliably predicted. He stated the AACE recognizes use of contingency to mitigate unexpected, additional costs as industry best practices.

Mr. Bull testified that once NIPSCO successfully completes various stages of a project and is able to determine that a risk that was used to support a contingency amount was not realized, the contingency amount is reduced and is shown on a Project Change Request ("PCR") form that is provided in plan update filings to support material project estimate changes during the current year for projects.

Mr. Bull testified that maintaining an appropriate contingency can actually prevent project cost increases by providing a process that avoids costly project interruptions or delays when an issue or risk is realized. He explained contingency (1) increases transparency for the project stakeholders and provides the Project Manager with an appropriate tool to manage issues or risks that may be realized during project development or execution; (2) provides the Project Manager with resources to avoid detrimental trade-offs in schedule, scope, quality, or functionality; and (3) ultimately, increases the confidence in completing the project within the estimated cost. Mr. Bull testified the contingency incorporated in the estimates for each of the 2020-2025 Gas Plan projects is consistent with industry practice for these types of projects and is consistent with the AACE Recommended Practice and NIPSCO's experience for risk that can impact a project cost gained through the execution of projects within Gas Plan 1. Mr. Bull fully explained the process used by NIPSCO to determine the appropriate contingency and discussed NIPSCO's process of documenting the risks considered in establishing the contingency for each project.

Mr. Bull testified that the basis for the cost estimates in the 2020-2025 Gas Plan vary from 2017 to 2020 based on engineering maturity, including material, construction costs, and the cost for engineering or other professional services. He stated the 3% annual escalation factor is only intended to address expected inflation-based cost increases in material, labor, and other resources under normal circumstances, not to address project risk or uncertainty. He explained that escalation is separate and distinct from contingency, and addresses different risks (cost increases). Mr. Bull also noted that the 3% annual escalation factor is only applied to base cost capital estimates, not to the contingency. The AACE recognizes use of escalation as an industry best practice to mitigate likely cost increases.

For each project category in the 2020-2025 Gas Plan, Mr. Bull described the purpose and explained how NIPSCO determined the projects for each year of the Plan. For each project included in the 2020-2025 Gas Plan, Mr. Bull described the project and explained how the estimate was developed. Additionally, for the Transmission Pipeline Installation Projects, Mr. Bull also explained alternatives that were considered and how the contingency was developed and what risks were anticipated to support the contingency. He also explained how the contingency was developed and what risks were anticipated to support the contingency for the Inspect & Mitigate and Storage Projects.

Mr. Bull testified the 2020-2025 Gas Plan includes $183,421,531 (direct dollars) over six years for the extension of natural gas service into currently unserved areas. He explained the forecast in the Plan are the costs associated with designing and installing gas main and service projects to reach rural areas. He described how NIPSCO would administer the rural gas extension process and stated NIPSCO's approach is consistent with the way it designs and executes other, non-TDSIC extension projects. Mr. Bull then explained how the estimate was developed and testified unit costs associated with rural extensions will be updated once per year along with the assumptions underlying the forecasted connection rate.

Ms. Becker summarized that NIPSCO followed a rigorous project development, cost estimating, and review process to provide its best estimate for each project included in the Plan. Mr. Bull explained large projects include a detailed work scope, preliminary engineering, route reviews, desk-top and on site real estate and environmental reviews. Cost data from recent projects and updated budgetary quotes from construction contractors were used as the basis for the estimates in most cases, with experience modifiers considered for site specific conditions. Small projects are generally based on parametric or unit price estimates that reflect a mix of contractor and internal labor resources similar to the allocation of work maintained during Gas Plan 1, and a review of routes and site conditions for many of the projects. For all projects, NIPSCO sought broad internal stakeholder input to assure comprehensive integrated work scopes were documented and validated through a formal review process. Mr. Racher testified NIPSCO's estimates for indirect costs and AFUDC are consistent with Generally Accepted Accounting Principles and the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts for utilities and NIPSCO's methodologies used for estimating these costs have not changed since its last general rate case.

D. **Public Convenience and Necessity.** Mr. Bull testified the eligible improvements included in the 2020-2025 Gas Plan are required or will be required to maintain the safety, integrity, and reliability of NIPSCO's transmission, distribution, and storage systems consistent with the public convenience and necessity. He stated that rural extensions have been determined by the General Assembly to be in the public interest as reflected in the statutory advantages the TDSIC Statute provides for them in comparison to other extension projects.

Ms. Becker testified NIPSCO's Plan is largely a replacement plan based upon the condition of these facilities. She explained that in order to continue serving customers safely and reliably while also complying with applicable laws, the public convenience and necessity require that the assets identified in the 2020-2025 Gas Plan be replaced. She stated the public's reliance on natural gas is linked directly with quality of life, economic enhancement and overall public safety. She testified NIPSCO takes its role seriously in serving its customers safely and reliably, and this includes protecting customers and employees from potential injury, and property damage associated with the operation of its gas transmission, distribution, and storage systems.

Ms. Becker testified NIPSCO's 2020-2025 Gas Plan follows the requirements of the TDSIC Statute and achieves the legislative intent of making new and replacement transmission, distribution, and storage system investments for the purpose of safety, reliability, system modernization and economic development, which is consistent with public policy and serves the public interest.

Ms. Becker testified the eligible investments contained in the 2020-2025 Gas Plan are essential in protecting the integrity, safety, and reliable operation of the system. She explained these investments provide for the public convenience and necessity at a much broader level by enhancing the ability of NIPSCO customers to take advantage of the rapid development of alternative natural gas supply and delivery options both now and into the future and position NIPSCO's system to remain reliable and flexible in the face of significant changes to the economic and operational climate for natural gas.

Ms. Becker stated the extension of gas service to rural areas will allow some residents in NIPSCO's service territory to access natural gas services for the first time. She explained that this portion of the Plan alone addresses the need of the currently unserved public to gain access to natural gas service. Ms. Becker testified for all these reasons, approval of the 2020-2025 Gas Plan is and will be required for the public convenience and necessity.

E. <u>Plan Benefits</u>. Mr. Bull testified the 2020-2025 Gas Plan focuses on maintaining safe, reliable service for NIPSCO's customers. He stated that while the Plan addresses all four types of eligible investment in the TDSIC Statute (safety, reliability, system modernization and economic development), most of the Plan's investments positively impact public safety. He explained that (1) safety drivers focus on risk reduction related to gas system leaks, pipeline ruptures, or incidents of pressure excursion; (2) reliability drivers include the avoidance of gas outages or curtailments driven from the inability to maintain gas system pressure during peak load events; and (3) system modernization impacts both safety and reliability by upgrading the facilities to current industry standards. He testified the 2020-2025 Gas Plan also extends the benefit of natural gas service to rural areas.

Mr. Bull said the estimated costs of the eligible transmission, distribution, and storage system improvements included in the 2020-2025 Gas Plan justified by incremental benefits attributable to the Plan and provides incremental benefit for NIPSCO's customers by significantly decreasing the potential risk associated with older or less than optimal facilities, by investing in upgrades to the deliverability on the system, to ensure continued and improved system reliability, and by extending the benefit of natural gas service to rural areas that are currently without that option.

Mr. Bull described how NIPSCO approached the quantification of incremental benefits associated with the 2020-2025 Gas Plan. He said NIPSCO expects to see an aggregate reduction in the risks associated with the transmission projects in the Plan of more than 80%, and each of the distribution and storage projects included in the Plan has been designed and chosen with the intent to reduce the likelihood of failure and the attendant risk to service reliability and continuity and the availability of system capacity. He testified the benefit to NIPSCO's customers from these investments cannot be calculated in an actuarial calculation. He explained that while it would be convenient if the benefit of each of the transmission, distribution, and storage projects could be quantified in monetary terms to permit some kind of a cost/benefit analysis, the value to be placed on life and property potentially at risk from the failure of one of these assets is too high to realistically contemplate.

Mr. Bull did discuss the options considered for the projects proposed in the Plan with an eye toward the reduction of costs whenever that could be accomplished while maintaining appropriate system benefits. He noted that the Commission previously found that the projects encompassed in NIPSCO's Gas Plan 1 provided incremental benefit through a reduction in system risk associated with the replacement of aging assets, and avoidance of the consequences of service deterioration and capacity restraint.[3] He testified the same is true of the projects proposed in the 2020-2025 Gas Plan.

Ms. Becker reiterated that the estimated costs of the eligible improvements included in the 2020-2025 Gas Plan are justified by the reasonably expected incremental benefits attributable to the Plan effectively addressing safety, reliability, system modernization, and the extension of gas service into rural areas. She indicated it is essential in considering the incremental benefit of the Plan to recognize that continued safe, reliable service from the eligible investments in the Plan be compared against the potential for service deterioration and capacity restraint that would occur if these investments were not made.

F. Plan Updates. Mr. Bull testified regarding NIPSCO's plan update process. He stated that while considerable analysis and thought went into the development of the 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 exist at the time the Plan was developed. As NIPSCO completes ongoing system analyses in the upcoming years, the Plan will be updated at least annually under Section 9 of the TDSIC Statute. Mr. Bull testified NIPSCO proposes to follow an update process very similar to the process from Gas Plan 1. He stated NIPSCO proposes to continue the current process of meeting with its stakeholders approximately four weeks prior to filing each Plan update. He explained that in each filing (1) the Plan will be updated with

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[3] Cause No. 44403 (April 30, 2014) at p. 22.

NIPSCO's best estimate by project for each calendar year; (2) confidential appendices to the Plan will be updated as new, relevant information becomes available during the Plan update process (3) PCR forms will be provided to support material project estimate changes during the current year for projects, (4) actual costs (direct capital, indirect capital, and AFUDC) will be included in the Plan update when a given calendar year is closed out, and (5) rural extension inputs will be updated annually. Ms. Becker testified NIPSCO each plan update filing will also include a description of any moves between project years, and explanations of all increases that exceed the greater of $100,000 or 20%.

G. <u>TDSIC Plan Development and PS&I Costs</u>. Mr. Bull explained that the total estimated capital cost of the 2020-2025 Gas Plan include plan development costs and preliminary survey and investigation ("PS&I") costs. He described that (1) PS&I costs for specific projects will be included in the project's construction work order (direct capital) and typically will be transferred to the first year of project construction, and (2) approximately $1.5 million of plan development costs will be amortized over the life of the Plan as capital overhead (or indirect capital), which is consistent with how NIPSCO allocated plan development costs in Gas Plan 1.

H. <u>Accounting and Ratemaking</u>. Mr. Racher described NIPSCO's accounting and ratemaking treatment to be used to record and recover costs associated with NIPSCO's 2020-2025 Gas Plan. He explained NIPSCO anticipates recovering approved capital expenditures and TDSIC costs associated with the 2020-2025 Gas Plan through its existing Gas TDSIC Mechanism, consistent with the Commission's January 28, 2015 Order in Cause No. 44403 TDSIC 1 ("TDSIC-1 Order").[4]

Mr. Racher described NIPSCO's currently approved ratemaking treatment for recovery of approved capital expenditures and TDSIC costs, including how (1) the TDSIC revenue requirement is calculated, (2) the return on capital costs and expenses included in the revenue requirement are calculated, (3) NIPSCO includes the reconciliation of costs in the revenue requirement calculation, (4) NIPSCO defers, until recovery through the TDSIC, 80% of the post in service TDSIC costs of the TDSIC projects, including carrying costs and pretax returns, depreciation, O&M and taxes, and (5) NIPSCO treats the remaining 20% of TDSIC capital expenditures and costs that are not included for recovery through the TDSIC adjustment factor.

Mr. Racher testified NIPSCO depreciates the TDSIC capital expenditures according to each asset's designated FERC account classification. Upon being placed in service, NIPSCO depreciates each asset according to the FERC account composite remaining life approved in the Commission's most recent gas rate case order (Cause No. 44988).

Mr. Racher explained that in each plan update filing, NIPSCO allocates the transmission, distribution, and storage system revenue requirements consistent with the revenue allocation approved by the Commission in NIPSCO's most recent base rate proceeding (Cause No. 44988) and recovers through a volumetric factor calculated in each plan update filing.

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[4] NIPSCO's Rider 488 (now Rider 188) – Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charges and Appendix F – Transmission, Distribution and Storage System Improvement Charges Adjustment Factor (the "Gas TDSIC Mechanism").

Mr. Racher testified the only change to NIPSCO's approved ratemaking treatment is to adjust its allocation percentages to reflect the significant migration of customers amongst the various rate classes for each plan update filing, to prevent any unintended consequences of the migration of customers between rates and to properly allocate the associated share of the revenue requirement.

Mr. Racher provided an overview of indirect capital costs and explained the steps used in determining the planned indirect capital costs that was used for the first two years of the Plan. He stated that the indirect percentages from the first two years of the Plan were used as a basis for the remainder of the plan and held constant at 13.5%. He indicated NIPSCO will provide plan updates for indirect costs as updated information becomes available. Mr. Racher testified the estimate for AFUDC is based on, among other things, the estimated direct and indirect project costs, estimated timing of the expenditures and current financing costs (which change over time). He stated the estimate used in the Plan is 3.5%. Mr. Racher testified NIPSCO's inclusion of indirect capital costs and AFUDC is consistent with NIPSCO's overhead capitalization and AFUDC methodologies which have been in place for years including during the test year used in NIPSCO's last general rate case (Cause No. 44988).

Mr. Racher also described the TDSIC Plan's estimated impact on retail revenues. He testified that, as shown below (Table 1 of his direct testimony), NIPSCO's TDSIC Plan does not result in an average aggregate increase in NIPSCO's total retail revenues of more than two percent in a 12-month period.

NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC

Estimated Revenue Requirement Based on TDSIC 2020 Proposed 6 -Year Gas TDSIC Plan (in millions)

		Estimated Revenues						
Line No.	**Rate Code**	**2018**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
1	111	$ -	$ -	$ 3.5	$ 8.4	$ 15.9	$ 25.2	$ 34.5
2	115	-	-	0.0	0.1	0.2	0.3	0.4
3	121	-	-	1.3	3.1	5.8	9.3	12.7
4	125	-	-	0.3	0.6	1.2	1.9	2.6
5	128	-	-	0.3	0.7	1.3	2.1	2.9
6	138	-	-	0.0	0.1	0.2	0.3	0.4
7	**Total**	**$ -**	**$ -**	**$ 5.4**	**$ 13.0**	**$ 24.6**	**$ 39.0**	**$ 53.4**

Table 1: Projected Impact on Retail Revenue from TDSIC Rate Schedule (in millions)

				2020	**2021**	**2022**	**2023**	**2024**	**2025**
1	Prior Year TDSIC Revenue			$ -	$ -	$ 5.4	$ 13.0	$ 24.6	$ 39.0
2	Incremental TDSIC Revenue			-	5.4	7.6	11.6	14.4	14.4
3	Total TDSIC Revenue			$ -	$ 5.4	$ 13.0	$ 24.6	$ 39.0	$ 53.4
4	Total Retail Revenue [1]	[2]	$ 820.6	$ 820.6	$ 826.0	$ 833.6	$ 845.2	$ 859.6	$ 874.0
5	Annual % Increase (Current line 2 ÷ prior line 4)	[3]			0.66%	0.92%	1.39%	1.70%	1.67%
6	Average Annual % Increase (Average of Line 5)								1.27%

[1] Assumes the revenues from base rates and charges and all trackers is constant prior to and as of 9/30/2019
[2] Operating revenue of $820,600,163 for the twelve months ended 9/30/2019

5. OUCC'S Case-in-Chief.

Mr. Krieger determined the proposed projects are eligible transmission, distribution, and storage system improvements under Ind. Code § 8-1-39-2, and NIPSCO provided the best estimate of the eligible improvements under Ind. Code § 8-1-39-10(b)(1) but recommended a 2% escalation factor is more reflective of the average annual Consumer Price Index ("CPI") reported by the United States Bureau of Labor Statistics which was 2.3 % for the 12 months ending February 2020. Mr. Krieger stated he is satisfied NIPSCO has provided best estimates and will solidify estimates, in the update process, when the later year projects become imminent. Mr. Krieger found NIPSCO was thorough in recognizing the potential "what if" projects specific to a project and recommended NIPSCO address major project contingency outcomes in the update process to better understand its use of contingency in the estimating process.

Mr. Krieger determined the public convenience and necessity require or will require the eligible improvements included in the plan under Ind. Code § 8-1-39-10(b)(2). He stated the risk analysis indicates these projects will improve NIPSCO's system for reliable natural gas delivery during the Plan installation and into the future. He added that for some pipelines, vintage year alone suggests replacement is required. He indicated that with dollar quantified benefits, the Commission would have one metric to aid in deciding if NIPSCO is providing the best use of rate payer dollars and ascertain the worth of selecte4d projects compared to non-selected projects.

Mr. Krieger determined NIPSCO has not met the requirement of Ind. Code § 8-1-39-10(b)(3) for proving the estimated costs of the eligible improvements are justified by the incremental benefits. Based on his analysis, Mr. Krieger testified NIPSCO provided the cost of the projects and demonstrated the benefits of the plan through the reduction of risk but recommended denial of NIPSCO's application because NIPSCO did not provide evidence of quantifiable benefits for risk reduction of chosen projects versus excluded projects. He stated that although NIPSCO provided a general explanation of its review of projects for the Plan, NIPSCO did not provide the exact methodology that shows how a specific was or was not included in the plan. Mr. Krieger did state that he is satisfied the EN Engineering report is supported by the evaluation of comprehensive risk magnitudes applied to those risks evaluated.

Mr. Krieger recommended continued use of NIPSCO's definitions of key terms from Cause No. 44403.

Mr. Krieger recommended approval of NIPSCO's proposal for updating the Plan. He also recommended NIPSCO should provide work order level detail cost estimates for all projects, including rural extensions, now lacking site specific engineering based upon site investigations completed for final design, material / labor procurement and scheduling, which should include work order level estimates for Plan projects originally based upon unit cost, parametrically derived costs, or preliminary design only projects. Mr. Krieger also requested NIPSCO continue informal communication and continue to improve the update process by including "costs tied to reasons" if best estimates or actual expenditures exceed a prior best estimate by 20% or $100,000. He described "costs tied to reasons" as explicitly naming the portion of work order detail causing the overage and the associated cost for the unplanned work order item. He also recommended NIPSCO file detailed work order level estimates, based on completed engineering with site visits, if NIPSCO requests a new project to be added.

Mr. Krieger recommended that NIPSCO (1) provide 20-year margin tests for defined rural extensions projects including work order level costs, customers, and estimated consumption, and (2) continue to work with the OUCC to ensure the accounting process is well understood so no project costs are double counted.

Mr. Grosskopf recommended approval of the portions of NIPSCO's proposed TDSIC mechanism and method for calculating a cost recovery revenue requirement that are consistent with NIPSCO's current TDSIC mechanism. He also did not oppose NIPSCO's proposed modification to adjust allocation percentages to reflect migration of customers among the various rate classes. Mr. Grosskopf recommended to address in a future TDSIC plan update filing adjustments to the weighted average cost of capital ("WACC") based on other information when determining the pre-tax return used.

6. Industrial Group's Case-in-Chief.

Mr. Phillips testified to the relevant background and history of NIPSCO's gas system and rate proceedings over the past 35 years. Mr. Phillips discussed the 22-year period between the 1988 and 2010 rate cases. Mr. Phillips stated that NIPSCO's depreciation rates were set at a high level in 1988, but NIPSCO did not perform any substantial system investments over that time, which resulted in a reduction in NIPSCO's rate base from $719 million in 1988 to $318 million in 2010. Because NIPSCO's rate base had fallen so much, the settlement that resolved the 2010 rate case provided for a fair value rate base of $726 million instead of book value and implemented a depreciation credit that would allow NIPSCO to better reflect the useful lives of system assets.

He discussed NIPSCO's first TDSIC plan, which was approved on April 30, 2014. That Plan approved cost estimates of $713 million, consisting of $593 million in direct capital and $120 million in indirect capital and AFUDC. The Plan focused on seven major long-needed projects to NIPSCO's high-pressure transmission system. However, less than a year and a half later, NIPSCO announced substantial delays affecting several of the major transmission projects, two of which were removed from the Plan in their entirety. At the same time, the estimated costs for the seven major transmission projects increased by nearly 60%. Despite the removal of the two of the seven major transmission projects and postponing other substantial work beyond the Plan period, the estimated costs of the Plan increased to $817 million, consisting of $677 million in direct capital and $140 million in indirect capital and AFUDC.

When NIPSCO filed its next rate case in 2017, Mr. Phillips described how NIPSCO's original cost rate base had increased to almost $1.5 billion, largely as a result of the TDSIC capital investment combined with the depreciation credit from the 2010 rate case settlement. The 2017 rate case also resulted in a settlement, which reduced the rate impact on large volume customers from a 70% increase to a still dramatic 39%.

Mr. Phillips discussed how, after the 2017 rate case was settled, the TDSIC plan had increased to $850 million in total capital. Following a remand from the Indiana Supreme Court, NIPSCO reduced total capital to $680 million through a settlement approved in the TDSIC-9 proceeding. That settlement also established cost caps on recoverable costs through the remaining two years of the original Plan, which was scheduled to terminate at the end of 2020. However, at the end of 2019, NIPSCO terminated the original Plan and filed this proceeding.

Mr. Phillips stated that NIPSCO's proposed Plan seeks approval of $948.7 million in total capital, with nearly half the planned work relating to two of the original seven major transmission projects that were proposed in the first Plan but were not completed. Another quarter of the proposed Plan consists of rural extensions, but NIPSCO confirmed that it would continue the 80% margin credit that had been used in the prior Plan. With respect to the total capital, compared to the original plan, which involved $679.8 million over a seven-year period, or $97.1 million per year, the proposed plan over a six-year period would average $158.1 million annually, or about 63% higher than under the prior Plan.

With respect to the two major transmission projects that were also proposed in the prior Plan, Mr. Phillips discussed how in the six years from first being proposed, the cost estimates have increased 445%. Mr. Phillips stated that lack of system investment in the period after the 1988 rate case also contributed to a $474.4 million decrease in system value by 2010. Mr. Phillips stated that if NIPSCO had undertaken those improvements at an earlier point, they could have been completed at a fraction of the cost now proposed. Mr. Phillips stated that NIPSCO provided no good reason why the work could not have been performed much earlier at a much lower cost, instead of delaying the work until the budgets inflated so drastically. Further, Mr. Phillips stated that the risks that NIPSCO identifies now as the justification for the projects have been present and apparent for many years. Mr. Phillips stated that despite the Aetna to 483# Loop being the highest priority project in the original TDSIC Plan, NIPSCO still has not completed that project and customers are still several years away from seeing the benefits.

Mr. Phillips also discussed the rate implications of the proposed TDSIC Plan as a tracked expense, as well as for a future base rate case. In this case, Mr. Phillips stated that NIPSCO projects to recover $53.4 million annually through the TDSIC tracker, not including the 20% deferred to the next rate case. By the time of NIPSCO's next rate case, Mr. Phillips stated that NIPSCO's book value of its plant will increase another billion dollars, an increase of seven or eight times what it was in 2010. This will lead to another massive rate increase for ratepayers.

Despite this history, Mr. Phillips recommended the system work that NIPSCO plans to perform would provide operational benefits and should be completed. However, Mr. Phillips recommended close scrutiny of the cost estimates to prevent ratepayers from bearing excessive cost responsibility and further protections to mitigate the rate impacts, both in upcoming tracker proceedings as well as in NIPSCO's next rate case.

Mr. Phillips stated there are three components in particular that are excessive or unnecessary: (1) the contingencies in the estimates, (2) the escalation factor, and (3) the proposed indirect capital and AFUDC.

Mr. Phillips testified that the contingency allowance proposed by NIPSCO is unnecessary and should be disallowed. Mr. Phillips stated that the estimated costs for the two main transmission projects have already increased by 445% above what NIPSCO presented as its best estimate six years ago in Cause No. 44403. That increase dwarfs the proposed contingency requested by NIPSCO, and consequently any further risk should be borne by NIPSCO and not ratepayers. He stated that instead of preapproving contingencies for automatic recovery in rates, the Commission should apply the specific justification standard under the TDSIC Statute in the event of further unanticipated cost increases. Mr. Phillips testified that the statutory process places the burden on

NIPSCO to justify any excess costs and leaves the risk with NIPSCO to manage any contingencies that may not meet the specific justification standard.

Mr. Phillips testified that NIPSCO's 3% escalation factor should be reduced to 2%, to reflect the Federal Reserve's targeted 2% long-term inflation rate. He testified that the Commission recently found that a proposed escalation factor of 2.25% was excessive in Cause No. 45235, and that 2.1% was more consistent with the long-range outlook of the Federal Reserve and consensus economists. Like contingency, he stated that cost estimates approved by the Commission that include an inflation adjustment amount to preapproval of automatic increases under the TDSIC Statute and shifts additional risk to ratepayers and reduces NIPSCO's incentive to complete the work as cost-effectively as possible. The TDSIC statute provides a mechanism for NIPSCO to seek specific approval for resulting cost increases. Mr. Phillips stated that this was especially appropriate given that the hundreds of millions of dollars of additional cost were due to NIPSCO's delay in completing the work.

Mr. Phillips stated the projected levels of $109 million of indirect capital and $32.1 million of AFUDC are excessive and higher than actual experience in the past 5 years. Indirect capital and AFUDC are applied by NIPSCO as percentages to the direct capital spend. Although NIPSCO stated that its proposed indirect capital and AFUDC percentages of 13.5% and 3.5%, respectively, reflected NIPSCO's experience with the prior Plan, the most recent 5-year period average for indirect capital was 10.94% and for AFUDC was 2.5%. Mr. Phillips testified that the proposed use of the higher percentages would result in excessive costs in the Plan estimates, and would unnecessarily increase the amounts preapproved for recovery through rates. Mr. Phillips stated that percentages for indirect capital and AFUDC for 2014 were not included in the average because they were an outlier and not calculated using the General Ledger software implemented by NIPSCO starting in 2015. Mr. Phillips testified that similar to contingency and cost escalation, the TDSIC statutory mechanism provides a balanced approach that requires NIPSCO to provide substantial justification before rate responsibility for any increases is placed on customers, which gives NIPSCO a strong incentive to complete the work on budget.

Mr. Phillips stated the pretax return assumed by NIPSCO in its rate calculations is based on the return authorized in its last rate case, which is higher than appropriate in this context. He testified that the pretax return for TDSIC purposes should be significantly lower, to reflect the reduction in risk arising from preapproved rate recovery for rate base investments. In addition, he stated that the allowed return for TDSIC purposes should recognize that NIPSCO proposes to continue to collect return in base rates associated with removed assets while also adding incremental return under the TDSIC tracker for replacement assets performing the same functions. He noted that a prior appellate decision noted that the statute did not require netting, but that the Commission could consider the impact of duplicative recovery in determining the appropriate pretax return. Mr. Phillips recommended that the Commission should make a downward adjustment to the approved pretax return. Mr. Phillips stated that the approved 9.85% return on equity was excessive in the context of the continued recovery of replaced assets and in light of the significant risk reduction due to NIPSCO's tracking of major investments and expenses, such as its gas cost and other federally mandated costs. Unlike electric utilities, Mr. Phillips stated that gas utilities do not require major investments in production plant.~~Mr. Phillips recommended the system work that NIPSCO plans to perform would provide operational benefits and should be completed; however, the cost estimates presented by NIPSCO are excessive and in several respects~~

~~include inflated and unnecessary costs. He was particularly concerned with the increase in the cost estimates for two of the transmission projects that were included in NIPSCO's Gas Plan 1 and in the new plan. Mr. Phillips attributed those increases to the delay in completing the work. Ultimately, Mr. Phillips determined that the transmission upgrades are important projects to reduce risk and improve the reliability of service to NIPSCO customers, and recommended close scrutiny of the cost estimates to prevent ratepayers from bearing excessive cost responsibility and protections to mitigate the rate impacts, both in upcoming tracker proceedings as well as in NIPSCO's next rate case.~~

~~Mr. Phillips stated there are three components in particular that are excessive or unnecessary, (1) the contingencies in the estimates, (2) the escalation factor, and (3) the proposed indirect capital and AFUDC.~~

~~Mr. Phillips recommended the contingency allowance proposed by NIPSCO is unnecessary and should be disallowed. He stated that instead of preapproving contingencies for automatic recovery in rates, the Commission should apply the specific justification standard under the TDSIC Statute in the event of further unanticipated cost increases.~~

~~Mr. Phillips raised a concern that NIPSCO's 3% escalation factor should be reduced to 2%, to reflect the Federal Reserve's targeted 2% long-term inflation rate. He contended that cost estimates approved by the Commission that include an inflation adjustment amount to preapproval of automatic increases under the TDSIC Statute and shifts additional risk to ratepayers and reduces NIPSCO's incentive to complete the work as cost-effectively as possible. Mr. Phillips also contended that preapproved estimates that include escalation shifts additional risk to ratepayers and reduces NIPSCO's incentive to complete the work as cost-effectively as possible.~~

~~Mr. Phillips stated the projected levels of indirect capital and AFUDC are excessive and higher than actual experience in the past 5 years and suggested that it would be more reasonable to calculate indirect capital at the most recent 5-year period average of 10.94% and AFUDC at the most recent 5-year period average of 2.5%.~~

~~Mr. Phillips stated the pretax return assumed by NIPSCO in its rate calculations is based on the return authorized in its last rate case, which is higher than appropriate in this context. He recommended that the pretax return for TDSIC purposes should be significantly lower, to reflect the reduction in risk arising from preapproved rate recovery for rate base investments. In addition, he recommended that the allowed return for TDSIC purposes should recognize that NIPSCO proposes to continue to collect return in base rates associated with removed assets while also adding incremental return under the TDSIC tracker for replacement assets performing the same functions.~~

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

A. <u>Incremental Benefits</u>.

Mr. Bull responded to the OUCC's recommendation that the Commission deny NIPSCO's application because NIPSCO has not quantified the reduced risk associated with completion of projects included in the 2020-2025 Gas Plan in comparison to other projects not included. He pointed out that Mr. Krieger admits that NIPSCO identifies the cost of the projects and demonstrates the benefits of the 2020-2025 Gas Plan through the reduction of risk. See Krieger, p. 3. He explained that NIPSCO has demonstrated that the Plan is proposed to reduce risk of asset failure and maintain service reliability and, in doing so, the Plan provides incremental benefits compared to how the future may otherwise unfold. Mr. Bull testified NIPSCO has sufficiently prioritized and optimized the incremental benefits of its Plan and otherwise shown a sound basis for the proposed projects and associated costs. Based on his understanding of the standard the Commission has previously applied to the evaluation of incremental benefits under the TDSIC Statute, Mr. Bull testified the Commission should find that the estimated costs of the eligible improvements are justified by incremental benefits attributable to the Plan.

Mr. Bull listed the evidence NIPSCO provided in its case-in-chief to demonstrate that the projects included in the Plan provide incremental benefits through the reduction in system risk by replacing aging assets and the avoiding the of consequences of service deterioration and capacity constraints. He then provided a summary of the benefits by each investment segment included in the Plan.

In response to Mr. Krieger's criticism that NIPSCO did not provide a dollar quantification or demonstration that the incremental benefit for the projects justify the costs in comparison to other projects that were not selected, Mr. Bull noted that the OUCC has consistently agreed that NIPSCO's TDSIC projects provide incremental benefits to its customers by improving safety and reliability, yet in this proceeding the OUCC proposes that the Commission deny approval of the 2020-2025 Gas Plan based on the absence of some sort of formulaic assessment of project benefits and costs.[5]

Mr. Bull stated the Commission has consistently determined that the following constitute sufficient evidence to support a finding that the estimated costs of the eligible improvements included in a TDSIC plan are justified by the reasonably expected incremental benefits attributable to the plan:[6]

- replacement of aging infrastructure supports the need for replacement of those assets in a cost efficient and prioritized manner,

- that the plan will provide operational benefits, including improved safety and reliability, decreased system risk through replacement of older and obsolete equipment and introduction of modern materials,

- improved system integrity, reduced threats of failure, improved emergency response and customer education, and reduced excavation damages, and

- explanation of benefits from extending natural gas service to rural areas.

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[5] April 30, 2014 Order in Cause No. 44403 ("44403 Order"), p. 22; August 27, 2014 Order in Consolidated Cause Nos. 44429 and 44430 ("44429 / 44430 Order"), p. 20; February 17, 2014 Order in Cause No. 44370 ("44370 Order"), p. 5; September 20, 2017 Order in Cause No. 44910 ("44910 Order"), pp. 25-26.

[6] 44403 Order, p. 22; 44429 / 44430 Order, p. 20; 44370 Order, p. 5; 44910 Order, pp. 25-26; June 29, 2016 Order in Cause No. 44720 ("44720 Order"), p. 27; September 27, 2017 Order in Cause No. 44942, p. 9.

Mr. Bull noted that the only case that he is familiar with that the Commission commented on an effort to monetize incremental benefits was in Indianapolis Power & Light Company's ("IPL") recent TDSIC proceeding in Cause No. 45264. He explained that while IPL was able to monetize the value of avoiding service outages associated with asset failure from the customer experience perspective for some of its proposed projects, the Commission noted that IPL's supplemental analysis did not attempt to quantify all project benefits, but rather focused on projects that lend themselves readily to monetization. Mr. Bull stated that the benefit of the projects comprising NIPSCO's 2020-2025 Gas Plan would be very difficult to monetize without attempting to (a) assign a dollar value to the health and safety of NIPSCO's customers individually or in the aggregate; or (b) evaluate the economic impact of a gas outage on the enormous industrial customers served by NIPSCO's 483# Loop. As a result, Mr. Bull believes that the analysis previously and consistently performed by NIPSCO and accepted by the Commission is a preferable way to assess whether there are sufficient incremental benefits to justify the costs of the projects incorporated in NIPSCO's Plan.

Mr. Bull concluded that although Mr. Krieger asserts that a comparison of cost and risk reduction for projects included in the plan versus potential alternatives should be required, it is clear from previous Commission decisions that this is not a requirement and there is nothing in the TDSIC Statute that would indicate that such a comparison is necessary.

B. Best Estimate.

i. Escalation

Mr. Bull disagreed with the OUCC's contention that 2% is more reflective of the average annual CPI reported by the United States Bureau of Labor Statistics which was 2.3 % for the 12 months ending February 2020 and the Industrial Group's suggestion that 2% would be more reasonable to reflect the Federal Reserve's targeted 2% long-term inflation rate. He stated that the CPI cited by Mr. Krieger is derived from the comparative cost of consumer spending in eight categories (food and beverage, housing, apparel, transportation, medical care, recreation, communication, and other goods and services) and is a frequently used resource to adjust income and expenditure streams for changes in the cost of living and the Federal Reserve's long-term target inflation rate of 2% cited by Mr. Phillips is a target that is set based on consumer spending. Mr. Bull testified that neither of these approaches is a reasonable proxy for costs associated with large industrial construction projects, which are driven by the cost of labor and materials, not consumer goods, particularly given the amount of construction that has taken place in the utility sector over the past several years which has resulted in shortages of some materials as well as a rise in labor costs.

Mr. Bull described the factors that typically influence costs for material, labor, and other resources in transmission and distribution pipeline projects (i.e., the significant amount of work in the transmission pipeline industry over the last few years driven by the development of shale oil and gas fields, the expanded use of natural gas for power generation, and new Pipeline and Hazardous Materials Safety Administration ("PHMSA") regulations), all of which resulted in higher labor, material, and equipment costs. He testified that while there has been softening in the demand driven by the development of shale oil and gas fields, a sustained down-turn will be required before there will be any impact to labor agreements and that any potential stimulus that increases public works or infrastructure construction will also have an impact on the cost of projects because such spending will place further demands on the market.

Mr. Bull testified that in determining that a 3% escalation is appropriate, NIPSCO considered its experience on projects executed through its Gas Plan 1 and information that is likely to influence costs for the projects included in the 2020-2025 Gas Plan. He cited several examples supporting the conclusion that the proposed 3% escalation was based on consideration of specific market and contract conditions impacting labor rates, cost escalation for materials, and equipment availability.

Mr. Bull described the steps NIPSCO takes to limit contractor price increases by competitively biding its transmission pipeline projects, distribution projects, and blanket contracts to achieve the most favorable costs possible. He stated (1) use of blanket contracts (whereby work is bid on a per unit basis) can also be beneficial from a cost perspective for certain types of routine work by establishing a body of work that the winning bidder can count on, (2) routinely seeking to add qualified contractors to the bidder pool to assure adequate competition, (3) identifying the most efficient construction methods and engaging contractors in pre-planning work and in constructability reviews to evaluate efficiencies that can be achieved during construction, and (4) by employing more efficient methods, the hours required to complete projects are reduced, which partially mitigates the cost of labor increases.

Mr. Bull described the steps NIPSCO takes to limit material price increases by leveraging the size and scope of NiSource purchasing agreements to achieve the most favorable prices for distribution materials, and working with suppliers to negotiate mill-direct purchases, where NIPSCO would purchase material directly from the manufacturer with minimal intermediate supplier mark-up for transmission pipeline materials.

Mr. Bull disagreed with Mr. Phillips that cost estimates approved by the Commission that include an inflation adjustment amount to preapproval of automatic increases under the TDSIC Statute. He stated that from an execution standpoint, cost estimates that fail to include an appropriate inflation adjustment are simply less reliable because they fail to take into consideration conditions that are likely to occur. He explained that in putting together the 2020-2025 Gas Plan, NIPSCO's goal was to provide its best estimate of the costs of the Plan and, for the reasons he set forth, the inclusion of a 3% escalator is a realistic reflection of NIPSCO's expectations. He noted that Mr. Phillips' recommendation that NIPSCO's escalation rate be reduced to 2% would build in an unrealistically low escalation rate that would be inconsistent with NIPSCO's best estimate.

Mr. Bull disagreed with Mr. Phillips that preapproved estimates that include escalation shifts additional risk to ratepayers and reduces NIPSCO's incentive to complete the work as cost-effectively as possible. He testified the TDSIC Statute requires that NIPSCO provide a best estimate of the costs of the proposed Plan. He explained that the goal is to provide the best estimate of costs for all years of the Plan at the time approval is sought. He noted that if the actual costs of construction are lower than the approved estimate, NIPSCO's customers will pay that lower cost. He stated NIPSCO is not attempting to shift risk to its customers, but rather is providing the best estimate so that the Commission and NIPSCO's stakeholders have realistic expectations of the cost of the Plan. He explained that NIPSCO works aggressively to control costs through extensive planning, detailed constructability reviews, competitive bidding, and effective project management processes and has been transparent in providing full detail supporting its project costs down to the work order level. He testified NIPSCO has and will continue to put forth its best effort to execute projects in a safe, compliant, and cost effective manner.

Mr. Bull testified that to his knowledge, while the Commission has not found that a best estimate of costs should be limited to a 2% escalation factor,[7] the Commission has consistently approved NIPSCO's 3% escalation factor in both its gas and electric TDSIC plan filings. He distinguished the Commission order cited by Mr. Phillips finding that an escalation factor of even 2.25% was excessive and that escalation at 2.1% would be more consistent with the long-range inflation outlook of the Federal Reserve and consensus economists, explaining that finding was related to escalation of the cost of decommissioning electric generating facility, not the construction of gas transmission and distribution pipelines. Mr. Bull reiterated that use of a general inflation rate such as the Federal Reserve outlook is not representative of the cost escalation to be expected for industrial construction, which needs to accommodate for expected increases in material, labor, and other resources.

ii. <u>Contingency</u>.

Mr. Bull disagreed with Mr. Phillips that the contingency included in NIPSCO's cost estimates is unnecessary and should be disallowed and provided a summary of his extensive testimony included in his case-in-chief to support the level of contingency included in its cost estimates. *See* Bull Direct Testimony, pp. 31-46. He testified the Commission has consistently found that including contingency costs in the cost estimate is consistent with the AACE system and with industry practice,[8] and, in fact, the Commission recently stated "we find the exclusion of contingency from the cost estimate would be unreasonable and would not establish the best cost estimate as required by the TDSIC Statute." 45264 Order, pp. 22-23.

Mr. Bull disagreed with Mr. Phillips' contention that including contingency in cost estimates shifts additional risk to ratepayers and reduces NIPSCO's level of cost discipline during the execution of projects. He testified the TDSIC Statute requires that NIPSCO provide a best estimate of the costs of the proposed Plan and that the Commission has consistently concluded that a reasonable level of contingency is a part of the best estimate of the cost of a project. 45264 Order, pp. 22-23; *see also, supra,* Footnote 7. Mr. Bull stated NIPSCO has used and will continue to use discipline to execute each project regardless of the level of contingency included in the cost estimate and that contingency simply accounts for probable project risks that cannot be controlled in advance. Mr. Bull reiterated points from his extensive direct testimony to identify significant risks that exist for the projects included in NIPSCO's 2020-2025 Gas Plan that require a reasonable contingency.

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[7] *See,* e.g. July 12, 2016 Order in Cause No. 44733 ("44733 Order"), September 27, 2017 Order in Cause No. 44942, March 4, 2020 Order in Cause No. 45264 ("45264 Order"), 44910 Order, 44720 Order, 44429 / 44430 Order, Order, 44370 Order, 44426 Order.

[8] *See,* e.g. 44733 Order, September 27, 2017 Order in Cause No. 44942, 45264 Order, 44403 Order, 44910 Order, 44720 Order, 44429 / 44430 Order, Order, 44370 Order, 44426 Order. *See also,* September 4, 2019 Order in Cause No. 45183, September 19, 2018 Order in Cause No. 45007, July 12, 2017 Order in Cause No. 44889, and December 13, 2017 Order in Cause No. 44872.

Mr. Bull testified knowledge of risk helps inform proper contingency levels and NIPSCO is continuing to undertake activities to better understand project risks. As an example, he stated the following activities were undertaken as part of the 483# Loop project: (a) NIPSCO conducted two independent reviews for the project to identify the most efficient routing -- each of which considered at least three alternate routes; (b) NIPSCO has already begun negotiating rights of entry for real estate that the pipeline will cross and conducting soil bores and testing to identify contaminated areas or underground obstructions; (c) NIPSCO is working with utility owners and "pot-holing" or excavating around utilities in advance to identify the exact location and depths; (d) NIPSCO is working with one large landowner to research archived records to identify prior land uses and potential obstructions; and (e) NIPSCO has invited potential contractors on the project to review the drawings and the route and provide input to the design team related to potential construction issues and technologies that may be employed to reduce risk during construction.[9] He concluded that each of these activities has allowed NIPSCO to better understand the risks associated with the project, and, in turn, has allowed NIPSCO to reduce the contingency required for the project because there are fewer unquantified unknowns.

iii. <u>Plan Investments</u>.

Mr. Bull responded to Mr. Phillips' suggestion that NIPSCO could have completed the 2020-2025 Gas Plan projects at a much lower cost had it undertaken many of the investments included in the Plan between 1988 and 2010. He stated that while it might be true that some projects would have cost less 20 years ago, the conditions and regulations that require the significant investments in NIPSCO's transmission system in NIPSCO's 2020-2025 Gas Plan did not exist prior to 2010 and that NIPSCO's transmission pipeline system is now more than 20 years older than it was then. He stated the Nation's tolerance for risks related to transmission pipeline safety changed markedly following two major pipeline incidents in 2010, one in California (San Bruno) and one in Michigan (Enbridge) and that over the subsequent nine years, the National Transportation Safety Board and the PHMSA issued new safety recommendations and directives and promulgated new regulations that required the industry to inspect pipelines and evaluate the design and supporting documentation and undertake work to correct legacy design conditions that no longer met current standards. He explained that NIPSCO and others in the industry worked proactively to follow the development of the recommendations, directives, and proposed regulations and undertake assessments and projects to assure pipeline integrity.

Mr. Bull noted that in the Gas Infrastructure Study submitted in support of NIPSCO's Gas Plan 1 in Cause No. 44403, in April 2011, the Secretary of Transportation Ray LaHood and PHMSA issued a "Call to Action" for pipeline operators to undertake programs to accelerate the identification, repair, rehabilitation, and replacement of pipelines to ensure the fitness for continued service.[10] *See* Petitioner's Exhibit No. MGS-2 (Confidential), p. 12. He explained that in that proceeding, NIPSCO witness Steven M. Auld testified that while peer utilities had an

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[9] NIPSCO included a Google Earth "flyover" of the route to illustrate the route and convey some of the issues NIPSCO will manage. *See* Bull Direct Testimony, Confidential Attachment 2-D.

[10] Mr. LaHood now chairs the Quality Review Board advising NiSource on implementation of its pipeline Safety Management Systems. *See,* e.g. https://www.insideindianabusiness.com/story/40133470/ former-congressman-to-chair-nisource-review-board-ray-lahood, March 15, 2019.

average of 13% priority pipe in their distribution systems, NIPSCO had reduced the priority pipe on its system to 1.1%. *See* Petitioner's Exhibit No. SMA, p. 16 and Petitioner's Exhibit No. SMA-3 and that NIPSCO had also upgraded all of its low pressure systems to modern, fully regulated medium pressure systems with the exception of the former Kokomo Gas & Fuel Company system that was not acquired by NIPSCO until 1992.[11] He stated that the increased focus on pipeline safety measures has continued as evidenced by the publication of the final version of PHMSA's long anticipated Gas Transmission Rule on October 1, 2019.[12] Mr. Bull testified that in support of both its Gas Plan 1 and this proceeding, NIPSCO conducted an assessment of its transmission pipeline system to identify and prioritize pipeline segments most at risk and subsequently initiated projects to replace or upgrade certain segments to comply with the evolving safety directives and regulations.

In response to Mr. Phillips that the 483# Loop project is the highest priority project in the 2020-2025 Gas Plan and should have been completed earlier, Mr. Bull agreed that the 483# Loop project is important and accounts for over half of NIPSCO's daily gas deliveries, and the project will reduce operational risk both for NIPSCO and its large customers on the 483# system by providing a redundant feed to a significant part of the system, as well as provide transport customers with additional flexibility in terms of gas supply.

He testified NIPSCO has implemented programs to mitigate the operational risk to some degree and protect the 483# system, adding additional pipeline markers, implementing more frequent patrols, upgrading the corrosion protection system, and establishing a watch-and-protect program where a NIPSCO observer is present any time there is excavation work in the vicinity of the pipeline. In addition, completion of other projects first was required to provide the pipeline network required to feed into the 483# Loop for the benefits of the project to be realized. He explained that the Aetna to Tassinong project is the final project required to support the 483# Loop and that NIPSCO plans to construct these projects in a parallel sequence to establish the redundant feed as early as possible.

In response to Mr. Phillips that the current estimates for the Aetna to Tassinong project and the 483# Loop project exceed the estimates approved by the Commission in 2014 by 445%, Mr. Bull agreed that the cost of the project has increased markedly since it was initially proposed in 2014. He agreed that significant changes were made to the cost estimates between 2014 and 2015 when the 483# Loop project was removed from Gas Plan 1 stating that several aspects of the original project had not been fully reflected in the original cost estimate. He testified the current estimate for the revised project reflects completion of a significant amount of additional design work so that those deficiencies are not repeated.

Mr. Bull testified the Aetna to Tassinong and the 483# Loop projects proposed in the 2020-2025 Plan are not the same as the projects originally approved in 2014. He explained that significant changes were identified as NIPSCO proceeded through the design process and design

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11 The low pressure portion of the Kokomo system is currently being replaced as part of NIPSCO's Pipeline Safety Compliance Program approved by the Commission in Cause No. 45183.

12 84 FR 52180 (Oct. 1, 2019). On April 22, 2020, PHMSA announced a *Notice of Enforcement Discretion* in recognition of potential personnel resource constraints due to COVID-19.

reviews and that in this filing NIPSCO has also applied experience gained through the execution of other projects completed in Gas Plan 1. He described that the Aetna to Tassinong project was originally scoped to be a direct replacement for the existing 16-inch pipeline, but that as the design progressed it was determined that use of the existing 16-inch pipeline would limit the capacity of gas available through the back-feed requiring a number of changes. Mr. Bull then outlined those changes and outlined the changes from the preliminary design for the 483# Loop project, including:

- NIPSCO determined that the Aetna to Tassinong line required an upgrade to 24-inch pipe, and additional capacity was also required to support the 600# system and the 483# Loop for the loop to function as intended and to provide significant redundant capacity under all operating conditions;

- NIPSCO needed to add capacity to the 600# system to support the redundant 483# Loop and a large regulator station and an additional interstate pipeline interconnection was needed; and

- NIPSCO completed additional constructability reviews that confirmed significant challenges especially on the north end of the route due to the congested industrial corridor where the work was to occur.

Mr. Bull also explained changes from the preliminary design for the 483# Loop project that had served as the basis for the 2014 estimate, including:

- Significant changes were required based on experience gained in construction through a very complex, congested industrial corridor including a final design that now addresses the requirements associated with crossing 17 sets of railroad tracks in the final mile of the pipeline that, together with other route modifications, added approximately one mile (16.7%) to the length of the route;

- There were several locations where the preliminary design did not account for the line running outside of existing NIPSCO rights-of-way; and

- The preliminary design anticipated the retirement of a very old, high risk 14-inch high pressure distribution line running parallel to the new 483# Loop, but didn't account for additional regulator stations and pipe required to reconnect customers served by the old line to be retired.

C. <u>Plan Update Process</u>.

In response to Mr. Krieger's recommendation that NIPSCO (1) inform the OUCC if it anticipates a project will exceed the approved best estimate by greater than 20% or $100,000, and supply reasons with estimated costs for those overages, thus creating a new best estimate request for approval; and (2) supply reasons substantiated with actual costs incurred if a project's actual costs exceed an approved best estimate by greater than 20% or $100,000, Mr. Bull testified that NIPSCO already provides that information in its current Plan Update process and has agreed to continue to provide that information in future Plan Updates. He described that the current process includes:

- Meeting with its stakeholders approximately four weeks prior to filing each Plan update;
- Updating the Plan in each filing with NIPSCO's best estimate by project for each calendar year;
- Providing variance explanations for each project in the Plan Update to explain any estimate changes from the previously approved estimate.
- Updating Confidential Appendix 1 (Transmission Risk Comparison) as new, relevant information becomes available;
- Updating Confidential Appendix 2 (Gas Asset Registers and Project Estimates) that includes detailed cost information as new, relevant information becomes available;
- Updating Confidential Appendix 3 (Summary of Unit Cost Estimates) broken down by direct costs including labor, material and other for projects with unit based estimates;
- Providing new estimate summaries to support individual project costs;
- Providing PCR forms to support changes that are +/- $30,000 or 15%, whichever is greater, or any estimate changes that exceed $100,000 for any project even if it does not meet the 15% threshold, for project estimate changes;
- Actual costs (direct capital, indirect capital, and AFUDC) when a given calendar year is closed out; and
- Updating rural extension inputs annually to show the projected costs for rural extensions by category (Mains and Service Lines inclusive of Meter Loops and Regulators) along with the number of new service connections projected by year.

Mr. Bull also stated that in conjunction with the OUCC, NIPSCO developed 19 items to provide with each Plan Update filing to assist the OUCC in its review and has modified what is provided, throughout the process, based on input from the OUCC. He testified NIPSCO is open to discussing at any time improvements in the information that is currently provided in the audit package to ensure it is meeting the OUCC's needs without providing unhelpful or an overwhelming amount of information. He noted that NIPSCO also plans to continue offering to meet with the OUCC after the filing is made to answer any questions as it begins its review in an effort to expedite the OUCC's review and provide additional information as necessary.

Mr. Bull responded to Mr. Krieger's recommendation that NIPSCO provide refined project location and work order level cost estimates for Plan projects originally submitted on a per unit basis. He testified that NIPSCO will provide updated best estimates to projects that are unit based when new relevant information is available and to the extent that projects are initially estimated on a unit cost basis and later developed based on a project-specific basis, NIPSCO will continue to provide detailed information to support the detailed estimate.

In response to Mr. Krieger's recommendation that NIPSCO provide 20–year margin tests for defined rural extensions projects including work order level costs, customers, and estimated consumption, Mr. Bull testified NIPSCO is committed to working with its stakeholders to determine additional information that can be provided for rural extension projects. He stated that it is important to balance what information is useful to stakeholders without unduly burdening NIPSCO and/or providing voluminous information that is not helpful. He reiterated that while rural extensions are driven by customer demand, and it is difficult, if not impossible, to provide estimated consumption, NIPSCO will continue to work with stakeholders to provide greater clarity to the information that is provided.

Mr. Bull responded to Mr. Krieger's recommendation that NIPSCO continue to work with the OUCC to ensure the accounting process is well understood so no projects costs are double counted stating that as it has since the inception of Gas Plan 1, NIPSCO will continue to work with the OUCC to ensure the accounting process is well understood to make a determination that no project costs are double counted. He noted that Mr. Krieger testified that the OUCC had no difficulty being able to conduct its review to determine there were no duplicative costs between Gas Plan 1 and the 2020-2026 Gas Plan, and was able to confirm that the 2020-2026 Gas Plan did not include any projects contained within rate base from Petitioner's last rate case in Cause No. 44988. Therefore, Mr. Bull felt it is clear that NIPSCO and the OUCC have already been working together to ensure the OUCC has a good understanding of the various issues that have arisen throughout the process.

D. Accounting and Ratemaking.

i. WACC

In response to Mr. Grosskopf's recommendation that to address adjustments to the WACC based on other information when determining the pre-tax return used in future TDSIC semi-annual filings, Mr. Racher testified that unlike IPL, the Commission already granted NIPSCO its ratemaking authority for its TDSIC in its TDSIC-1 Order. He explained that NIPSCO has followed that ratemaking authority in each of its update filings and testified that in this proceeding, NIPSCO is not requesting any changes to its ratemaking authority with the exception of allocators.

Mr. Racher testified that in compliance with the Commission's TDSIC-1 Order authorizing NIPSCO to "use a full WACC, including zero-cost capital, to calculate pretax return," in each of its update filings, NIPSCO has included the total WACC calculation with the equity, debt, and zero cost components. TDSIC-1 Order at p. 28 (Finding 5(C)(4)). Also in compliance with the TDSIC-1 Order directing that "the WACC should be updated in each semi-annual TDSIC filing to reflect and updated capital structure and cost of debt," in each of its update filings, NIPSCO has included an updated WACC as of the capital expenditure date. TDSIC-1 Order at p. 28 (Finding 5(C)(4)).

Mr. Racher testified the Commission recently considered Ind. Code § 8-1-39-13 for determination of pretax return for NIPSCO's recent TDSIC filings in its October 16, 2019 Order in Cause No. 44403-TDSIC-10 (at 15), finding "[i]n 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." He stated the Commission approved a return on equity for NIPSCO gas in its September 19, 2018 Order in Cause No. 44988 (NIPSCO's most recent gas general rate case). He explained NIPSCO utilizes a holistic approach including all of the capital resources, including the zero cost items in the WACC calculation and that NIPSCO will use all capital resources (including equity, debt, and other zero cost items and the methodology approved from the most recent NIPSCO gas rate case in Cause No. 44988) to finance the TDSIC projects and follow its normal utility funding process. He testified this methodology is consistent with NIPSCO's other long-standing capital investment trackers.

Mr. Racher disagreed with Mr. Phillips' recommendation that the pretax return for TDSIC purposes should be significantly lower, to reflect the reduction in risk arising from preapproved rate recovery for rate base investments. He explained that a fair pretax return methodology was approved in NIPSCO's most recent gas rate case in Cause No. 44988 (Order dated September 19, 2018), in which the Industrial Group participated. He also noted that in its February 17, 2014 Order in Cause No. 44371, the Commission said, "[h]owever, we note that NIPSCO's authorized return equity of 10.2% was approved relatively recently in our 43969 Order on December 21, 2011. Further, we acknowledge the offsetting effects of this tracker's cost recovery security and timeliness and the increased investment being made for the associated projects. Consistent with our finding above on the appropriate capital structure, we decline to lower NIPSCO's authorized return on equity from that approved in its most recent case." Mr. Racher testified that given that the return determination was relatively recent, and given the TDSIC investments are new, a lower return should not be included in the return on those assets.

ii. Replaced Asset Investment Costs.

In response to Mr. Phillips' recommendation that the allowed return for TDSIC purposes should recognize that NIPSCO proposes to continue to collect return in base rates associated with removed assets while also adding incremental return under the TDSIC tracker for replacement assets performing the same functions, Mr. Racher testified the Commission previously addressed the treatment of netting current eligible TDSIC improvement amounts with the replaced asset investment costs. He explained that in its February 17, 2014 Order in Cause No. 44371 (p. 18), the Commission found:[13]

> The statutory definition of eligible improvements at Ind. Code § 8-1-39-2 authorizes recovery of investment for replacement projects and the definition of pretax return at Ind. Code § 8-1-39-3 provides that revenues should provide for such investments, notably without suggesting any deduction or netting of the replaced asset. Further, TDSIC costs as defined at Ind. Code § 8-1-39-7 includes this unadjusted pretax return. While acknowledging that Ind. Code § 8-1-39-13(a) allows the Commission to consider other information in setting the appropriate pretax return, we read this section to be addressing the weighted cost of capital rate

[13] *See also* Order on Reconsideration dated May 7, 2014, Finding No. 5.

> rather than the investment amount so as to reconcile the statutory language of Section 13 and 3. Accordingly, we do not find statutory support for the netting of investment in determining the appropriate investment to be afforded cost recovery. In addition, the TDSIC statute requires a general rate case before the expiration of the utility's 7-year plan which provides a built in mechanism to update the net investment of the utility. Thus, we decline to require NIPSCO to recognize the replaced asset investment cost already embedded in base rates because Ind. Code ch. 8-1-39 does not support it outside the required rate case.

Mr. Racher testified NIPSCO's projects included in the 2020-2025 Gas Plan are considered eligible improvements as defined in Ind. Code § 8-1-39-2, NIPSCO's next gas general rate case will include a review of all costs (both capital and the related expenses) associated with the TDSIC investments in the 2020-2025 Gas Plan, and NIPSCO will file another gas general rate case prior to the expiration of the 2020-2025 Gas Plan in compliance with Ind. Code § 8-1-39-9(e), the same criteria the Commission used in its 44371 Order addressing treatment of netting current eligible TDSIC improvement amounts with the replaced asset investment costs.

iii. Calculation of Indirect Capital and AFUDC.

Mr. Racher responded to Mr. Phillips' proposal to calculate indirect capital at the most recent 5-year period average of 10.94% and AFUDC at the most recent 5-year period average of 2.5%. He stated that NIPSCO reviewed its experience in Gas Plan 1 but did not use a historic average. He explained that the 2014 percentage was given no weight given the time that has passed and a change in reporting systems but that more weight was given to the recent 12.9% 2019 results while also using forward looking estimates from NiSource's Financial Planning and Analysis department. He testified that using this information as a guide, NIPSCO estimated 13.5% for indirect capital costs for the 2020-2025 Gas Plan and, in addition to incorporating experience from Gas Plan 1, NIPSCO increased the AFUDC estimate to 3.5% in the 2020-2025 Gas Plan to account for the large multi-year gas transmission projects which will accrue AFUDC during the duration of the project. He testified NIPSCO's estimates of indirect capital and AFUDC are part of its "best estimate" of the cost of the gas transmission, distribution, and storage system investments included in the Plan.

Mr. Racher testified that as in NIPSCO's current process, at such time as a calendar year is closed out (every other update filing), NIPSCO will update the indirect capital and AFUDC amounts to reflect the *actual* costs incurred. He stated that NIPSCO does not directly recover the indirect capital or AFUDC costs from customers but instead, in each update filing, NIPSCO only includes *actual* amounts of indirect capital and AFUDC included in project costs as of the capital expenditure date, which amounts are the basis of the capital revenue requirement calculation performed in each update filing.

8. Commission Discussion and Findings.

A. Statutory Framework. Ind. Code § 8-1-39-10 permits a public utility to petition the Commission for approval of the public utility's plan for eligible transmission, distribution, and storage improvements, which may include approval of a targeted economic development project. The Commission's order must include the following:

> (1) A finding of the best estimate of the cost of the eligible improvements included in the plan.
>
> (2) A determination whether public convenience and necessity require or will require the eligible improvements included in the plan.
>
> (3) A determination whether the estimated costs of the eligible improvements included in the plan are justified by incremental benefits attributable to the plan.
>
> If the commission determines that the public utility's TDSIC plan is reasonable, the commission shall approve the plan and authorize TDSIC treatment for the eligible transmission, distribution, and storage improvements included in the plan.

Ind. Code § 8-1-39-10(b).

> In seeking recovery of capital expenditures and TDSIC costs in future tracker proceedings:
>
> Actual capital expenditures and TDSIC costs that exceed the approved capital expenditures and TDSIC costs require specific justification by the public utility and specific approval by the commission before being authorized for recovery in customer rates.

Ind. Code § 8-1-39-9(g).

> "Eligible transmission, distribution, and storage system improvements" means new or replacement electric or gas transmission, distribution, or storage utility projects that:
>
> (1) a public utility undertakes for purposes of safety, reliability, 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) were [among other things] described in the public utility's TDSIC plan and approved by the commission under [Ind. Code § 8-1-39-10] and authorized for TDSIC treatment . . . .

Ind. Code § 8-1-39-2(a).

> The term "eligible transmission, distribution, and storage system improvements" includes the following:
>
> (1) projects that do not include specific locations or an exact number of inspections, repairs, or replacements, including inspection based projects such as pole or pipe inspection projects; and

> (2) projects involving advanced technology investments to support the modernization of a transmission, distribution, or storage system, such as advanced metering infrastructure, information technology systems, or distributed energy resource management systems.

Ind. Code § 8-1-39-2(b).

Ind. Code § 8-1-39-7.8 requires that a TDSIC plan cover a period of at least five years and not more than seven years.

Ind. Code § 8-1-39-10(d) allows a utility to "terminate an existing TDSIC plan before the end of the original plan period by providing the commission a notice of termination at least sixty (60) days before the date on which the plan will terminate."

Ind. Code § 8-1-39-11(c) provides:

> Notwithstanding any rule or law governing extension of service, a public utility that provides gas service may, on a non-discriminatory basis, extend service in rural areas without a deposit or other adequate assurance of performance from the customer, to the extent that the extension of service results in a positive contribution to the utility's overall cost of service over a twenty (20) year period. However, if the public utility determines that the extension of service to a targeted economic development project will not result in a positive contribution to the utility's overall cost of service over a twenty (20) year period, the public utility may require a deposit or other adequate assurance of performance from: (1) the developer of the targeted economic development project; or (2) a local, regional, or state economic development organization.

B. NIPSCO's TDSIC Plan and Eligible Improvements. NIPSCO's TDSIC Plan is comprised of three segments: (1) investments aimed at maintaining the system reliability through the capacity of the system to deliver gas to customers when they need it (Gas System Deliverability); (2) replacement of certain system assets to ensure the ongoing integrity and safe operation of the gas system (Gas System Integrity); and (3) the extension of gas facilities into rural areas (Rural Gas Extensions). NIPSCO's TDSIC Plan and attached appendices identify what projects will be undertaken, when they will be undertaken, and why these projects are necessary and beneficial. The evidence presented demonstrates that the improvements are being undertaken by NIPSCO for purposes of safety, reliability, system modernization, or economic development. NIPSCO also showed that the proposed improvements were not included in its rate base in its most recent general rate case.

The witnesses for the other parties did not challenge the TDSIC Plan on the basis that the projects are not "eligible improvements" under applicable law. Thus, based on the evidence, we find that the projects described in NIPSCO's TDSIC Plan meet the criteria established by the TDSIC Statute and find that the projects are being undertaken by NIPSCO for the purpose of safety, reliability, system modernization, and support of economic development. We further find that the proposed projects are "eligible improvements" as defined in Ind. Code § 8-1-39-2 and were not included in NIPSCO's most recent rate case.

C. NIPSCO's Proposed Definitions. While Ind. Code § 8-1-39-1 states that definitions in Ind. Code § 8-1-2-1 apply, there are several terms that are not defined elsewhere, and therefore, NIPSCO is proposing to continue to use definitions for the following key terms: Safety; Reliability; System Modernization; Economic Development; Transmission and Distribution; and Under Construction as approved by the Commission in Cause No. 44403. NIPSCO is also proposing that the Commission retain the definition for Rural Area as accepted by the Commission in Cause No. 44403 solely for the purpose of administrative convenience. No party opposed NIPSCO's proposed definitions. We find NIPSCO's continued use of the definitions approved in Cause No. 44403 is reasonable and is approved.

D. Best Estimate of Costs.

Ind. Code § 8-1-39-10(b)(l) requires that the Commission's order on a TDSIC Plan must include "[a] finding of the best estimate of the cost of the eligible improvements included in the plan."

NIPSCO's TDSIC Plan proposes six years of defined investment totaling $807,573,279 in direct capital and an additional $141,103,241 in indirect capital and AFUDC, for a total of $948,676,520. The estimated Plan direct capital cost addresses $92,656,660 (11%) of gas system deliverability projects, such as adding new gas mains and adding or upgrading regulator stations to improve NIPSCO's ability to meet customers' deliverability demands; $531,495,088 (66%) of gas system integrity projects, such as replacing certain segments of NIPSCO's gas transmission, distribution, and storage facilities to ensure public safety, and asset replacements identified to be at risk of continued operability through routine and special inspection and assessment cycles; and $183,421,531 (23%) of rural gas extension projects making investments in new or upgraded gas mains and / or regulator stations, and new services to make natural gas available to rural customers. The total direct capital cost estimate is $598,060,860 transmission cost; $193,896,775 distribution costs; and $15,615,644 storage costs. NIPSCO's TDSIC Plan provides year-by-year project details, including cost estimates in a sortable list and an associated summary of the Plan's cost by FERC account (TDSIC Plan, Page 2).

NIPSCO developed cost estimates for the projects included in the TDSIC Plan using the AACE Cost Classification System. The confidential appendices included in NIPSCO's TDSIC Plan included a risk register, asset registers, project estimates, and unit cost estimates. Further, as part of its periodic update process, NIPSCO plans to update the Plan and include information regarding its cost estimates by project for each calendar year. In accordance with Ind. Code § 8-1-39-9(g), any costs in excess of approved expenditures and costs will be subject to review under the specific justification standard before being authorized for recovery in rates. NIPSCO will provide PCR forms to support material project estimate changes during the current year for projects. Actual costs (direct capital, indirect capital, and AFUDC) will be included in the Plan update when a given calendar year is closed out. Rural extension inputs will be updated annually.

Although NIPSCO's estimates are based on the AACE Cost Classification System, we echo Mr. Phillips' concerns with the increase NIPSCO has proposed with respect to the two major transmission projects that were originally proposed in NIPSCO's prior TDSIC Plan. Based on the 445% increase in those two major projects, which combine for almost half of the entire 6-year TDSIC spend, Mr. Phillips recommended that the contingency included in NIPSCO's cost estimates is unnecessary and should be disallowed. Instead of including contingency in NIPSCO's best estimate, Mr. Phillips recommended that the Commission focus on the Section 9 requirements of the TDSIC statute, and that in future tracker proceedings, NIPSCO demonstrate specific justification if there is a need to increase the cost estimates from the amounts approved in this proceeding. In light of the massive cost increases, we find that inclusion of additional contingency, which are established from the increased base cost of the projects, would unreasonably shift the burden to maintain cost control from NIPSCO to ratepayers. Any further increases to NIPSCO's cost estimates should be made in the context of the tracker proceeding in which NIPSCO will need to demonstrate specific justification for the increase. Given these considerations, we find the exclusion of contingency from the cost estimate is appropriate and will not be included in the best cost estimate as required by the TDSIC Statute.

Industrial Group witness Mr. Phillips and OUCC witness Mr. Krieger also recommended that NIPSCO's escalation rate should be reduced to 2%, which is the current target inflation rate of the Federal Reserve. While Mr. Bull attempted to differentiate our approval of a reduced 2.1% escalation factor in the context of a decommissioning cost estimate discussed in Cause No. 45235, we note that decommissioning projects, like gas construction projects, are utility capital projects that involve material, labor, and supplies. We see no reason to further increase cost escalation beyond the Federal Reserve target inflation rate. Again, as noted above, NIPSCO has the opportunity to demonstrate specific justification for increases beyond the approved 2% escalation, which is already subject to compounding over the six-year term of the Plan. Given these considerations, we find the reduction of escalation to 2% in the cost estimate is appropriate and would establish the best cost estimate as required by the TDSIC Statute.

Regarding indirect capital cost and AFUDC, Industrial Group witness Mr. Phillips suggested that it would be more reasonable to calculate indirect capital at the most recent 5-year period average of 10.94% and AFUDC at the most recent 5-year period average of 2.5%. In contrast, NIPSCO proposed percentages that are higher than any of the actual figures used by NIPSCO in any of the past five years, indicating that it relied on increased indirect capital costs for 2019 and forward looking estimates from NiSource's Financial Planning and Analysis department, and further increasing AFUDC to 3.5% to account for the large multi-year gas transmission projects. We find that the historic average approach provides a reasonable reflection of projected indirect costs and AFUDC, and that NIPSCO's higher proposal has not been supported with quantifiable and reliable data. Accordingly, we find that NIPSCO's estimates of indirect capital and AFUDC should be limited to the historic five-year average of 10.94% and 2.5%, respectively.

Based on the evidence presented, we find that the record demonstrates that the estimated cost of NIPSCO's TDSIC Plan should include only the base project cost, without additional contingency allowance, subject to an escalation factor of 2.0%, and indirect capital cost and AFUDC limited to 10.94% and 2.5% respectively, which rests on a sound factual and analytical foundation and is reasonable. Accordingly, we find the best estimate of the cost of the eligible improvements included in the Plan is the resulting amount based on the findings herein.

~~Ind. Code § 8-1-39-10(b)(l) requires that the Commission's order on a TDSIC Plan must include "[a] finding of the best estimate of the cost of the eligible improvements included in the plan."~~

~~NIPSCO's TDSIC Plan proposes six years of defined investment totaling $807,573,279. The estimated Plan cost addresses $92,656,660 (11%) of gas system deliverability projects, such as adding new gas mains and adding or upgrading regulator stations to improve NIPSCO's ability to meet customers' deliverability demands; $531,495,088 (66%) of gas system integrity projects, such as replacing certain segments of NIPSCO's gas transmission, distribution, and storage facilities to ensure public safety, and asset replacements identified to be at risk of continued operability through routine and special inspection and assessment cycles; and $183,421,531 (23%) of rural gas extension projects making investments in new or upgraded gas mains and / or regulator stations, and new services to make natural gas available to rural customers. The total cost estimate is $598,060,860 transmission cost; $193,896,775 distribution costs; and $15,615,644 storage costs. NIPSCO's TDSIC Plan provides year-by-year project details, including cost estimates in a sortable list and an associated summary of the Plan's cost by FERC account (TDSIC Plan, Page 2).~~

~~NIPSCO developed cost estimates for the projects included in the TDSIC Plan using the AACE Cost Classification System. As a general matter, the preliminary engineering for most projects in NIPSCO's TDSIC Plan would support a Class 4 estimate based on the application of recent construction experience, added efforts to inspect and understand site conditions, identify real estate and environmental requirements, and characterize the project risks, especially on the larger transmission projects. The confidential appendices included in NIPSCO's TDSIC Plan included a risk register, asset registers, project estimates, and unit cost estimates. The level of detail NIPSCO used to estimate project cost estimates in its TDSIC Plan is consistent with common practice within the industry.~~

~~Further, as part of its periodic update process, NIPSCO plans to update the Plan with its best estimate by project for each calendar year. The confidential appendices included in NIPSCO's TDSIC Plan will be updated as new, relevant information becomes available during the Plan update process. PCR forms will be provided to support material project estimate changes during the current year for projects. Actual costs (direct capital, indirect capital, and AFUDC) will be included in the Plan update when a given calendar year is closed out. Rural extension inputs will be updated annually.~~

~~We find that NIPSCO's estimates are sufficiently detailed and reasonably based on the AACE Cost Classification System. Industrial Group witness Mr. Phillips raised a concern that contingency included in NIPSCO's cost estimates is unnecessary and should be disallowed. However, we find that including contingency costs in the cost estimate is consistent with the AACE system and with industry practice. We also find that NIPSCO has shown that the level of contingency reflected in its cost estimates is reasonable. Given these considerations, we find the exclusion of contingency from the cost estimate would be unreasonable and would not establish the best cost estimate as required by the TDSIC Statute.~~

~~Industrial Group witness Mr. Phillips and OUCC witness Mr. Krieger raised a concern that NIPSCO's escalation rate should be reduced to 2%. However, we find that NIPSCO has shown that the level of escalation reflected in cost estimates is reasonable and was based upon consideration of a variety of specific factors rather than the more general information advocated in support of the Industrial Group and OUCC positions. Given these considerations, we find the reduction of escalation to 2% in the cost estimate would be unreasonable and would not establish~~

~~the best cost estimate as required by the TDSIC Statute.~~

~~Industrial Group witness Mr. Phillips also contended that cost estimates approved by the Commission that include an inflation adjustment amounts to preapproval of automatic increases under the TDSIC Statute and shifts additional risk to ratepayers and reduces NIPSCO's incentive to complete the work as cost-effectively as possible. We disagree. We find that cost estimates that fail to include an appropriate escalation factor or inflation adjustment are simply less reliable because they fail to take into consideration conditions that are likely to occur. We further find that NIPSCO's inclusion of a 3% escalation factor in its best estimate of the costs of the Plan is a realistic reflection of NIPSCO's expectations.~~

~~Industrial Group witness Mr. Phillips also contended that preapproved estimates that include escalation shifts additional risk to ratepayers and reduces NIPSCO's incentive to complete the work as cost-effectively as possible. To the contrary, inclusion of escalation in its best estimate of costs does not shift risk to its customers, but rather provides the best estimate so that the Commission and NIPSCO's stakeholders have realistic expectations of the cost of the Plan. We agree with NIPSCO that the goal is to provide the best estimate of costs for all years of the Plan at the time approval is sought. We further agree that if the actual costs of construction are lower than the approved estimate, NIPSCO's customers will pay that lower cost.~~

~~The TDSIC Statute requires that NIPSCO provide a best estimate of the costs of the proposed Plan. *See* Ind. Code § 8-1-39-10(b)(1). The Commission has not found that a best estimate of costs should be limited to a 2% escalation factor.[14] The Commission has, however, consistently approved NIPSCO's 3% escalation factor in both its gas and electric TDSIC plan filings. We conclude that the use of a general inflation rate such as the CPI or Federal Reserve outlook is not representative of the cost escalation to be expected for industrial construction, which needs to accommodate for expected increases in material, labor, and other resources.~~

~~Industrial Group witness Mr. Phillips suggested that it would be more reasonable to calculate indirect capital at the most recent 5-year period average of 10.94% and AFUDC at the most recent 5-year period average of 2.5%. However, we find that NIPSCO has shown that its methodology of (1) looking at the 12.9% indirect capital costs for 2019 and then adjusting to reflect forward looking estimates from NiSource's Financial Planning and Analysis department, and (2) increasing AFUDC to 3.5% to account for the large multi-year gas transmission projects that will accrue AFUDC during the duration of the project, is reasonable. We further find that NIPSCO's estimates of indirect capital and AFUDC are part of its best estimate of the cost of the Plan are a realistic reflection of NIPSCO's expectations.~~

~~Ind. Code § 8-1-39-10 requires the Commission order to include a "finding of the best estimate" of the cost of the proposed improvements. At this juncture, the Commission is not tasked with reviewing actual project costs. After approval of a TDSIC plan, Ind. Code § 8-1-39-9 establishes procedures for TDSIC trackers, providing that "[a]ctual capital expenditures and TDSIC costs that exceed the approved capital expenditures and TDSIC costs require specific justification by the public utility and specific approval by the commission before being authorized~~

~~[14] *See,* e.g. 44733 Order, September 27, 2017 Order in Cause No. 44942, 45264 Order, 44910 Order, 44720 Order, 44429 / 44430 Order, Order, 44370 Order, 44426 Order.~~

~~for recovery in customer rates."[15] Moreover, Ind. Code § 8-1-39-14 establishes a limitation on TDSIC recovery within a 12-month period. We find these sections adequately address the other parties' concerns about future variation in costs.[16]~~

~~Based on the evidence presented, we find that the record demonstrates that the estimated cost of NIPSCO's TDSIC Plan of $948,676,520 rests on a sound factual and analytical foundation and is reasonable. Accordingly, we find the best estimate of the cost of the eligible improvements included in the Plan is the estimate provided by NIPSCO.~~

E. Public Convenience and Necessity. Ind. Code§ 8-1-39-10(b)(2) requires that an order on a TDSIC Plan must include "[a] determination whether public convenience and necessity require or will require the eligible improvements included in the plan."

The evidence of record in this Cause demonstrates that the TDSIC Plan is largely a replacement plan based upon the condition of the facilities and which is necessary to continue serving its customers safely and reliably while also complying with applicable laws. The TDSIC Plan follows the requirements of the TDSIC Statute and achieves the legislative intent of making new and replacement transmission, distribution, and storage system investments for the purpose of safety, reliability, system modernization and economic development. The eligible investments are oriented on ~~essential in~~ protecting the integrity, safety, and reliable operation of the system, ~~and~~ enhanc~~es~~ing the ability of NIPSCO customers to take advantage of the rapid development of alternative natural gas supply and delivery options, and ~~also~~ positioning NIPSCO's system to remain reliable and flexible in the event of significant changes to the economic and operational climate for natural gas. Additionally, the extension of gas service to rural areas will allow some residents in NIPSCO's service territory to access natural gas services for the first time.

No party offered evidence demonstrating that the eligible improvements included in the TDSIC Plan were unnecessary for the continued safe and reliable service to customers or that the public convenience and necessity did not, or would not, require the TDSIC investments to be made.

Rural extensions have been determined by the General Assembly to be in the public interest as reflected in the statutory advantages the TDSIC Statute provides for them in comparison to other extension projects. Based on the evidence presented, we find that NIPSCO's approach to extending its gas system to rural areas is consistent with the TDSIC Statute and should be

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~~[15] NIPSCO witness Mr. Racher testified that as is NIPSCO's current process, at such time as a calendar year is closed out (every other update filing), NIPSCO will update the indirect capital and AFUDC amounts to reflect the *actual* costs incurred.~~

~~[16] While Mr. Phillips only contested (1) contingencies in the estimates, (2) escalation factor, and (3) magnitude of proposed indirect capital and AFUDC, we are also aware of the criticism he leveled about the magnitude of the industrial rate increase approved by the Commission in Cause No. 44988 ("[t]he case was eventually settled in 2018, and under the approved settlement the revenue increase for Rate 128 was 39%. I would still consider a 39% increase as a dramatic spike in rates.") Phillips Direct Testimony at p. 8. We note that not only was the Industrial Group signatory to the referenced settlement we approved in that cause, but that Mr. Phillips provided Settlement Testimony that concluded that the settlement was reasonable and in the public interest. *See* Cause No. 44988, Phillips Settlement Testimony at p. 7. That settlement also established the cost allocation methodology to be employed in TDSIC proceedings as also supported by Mr. Phillips. *Id.* at p. 5.~~

approved.

Thus, we find that substantial evidence in this Cause shows that the projects included in NIPSCO's TDSIC Plan will serve the public convenience and necessity.

F. <u>Incremental Benefits Attributable to the TDSIC Plan</u>. Ind. Code § 8-1-39-10(b)(3) requires that an order on a petition for approval of a TDSIC plan must include "[a] determination whether the estimated costs of the eligible improvements included in the plan are justified by incremental benefits attributable to the plan."

Ms. Becker testified the TDSIC Plan effectively addresses safety, reliability, system modernization, and the extension of gas service into rural areas. She stated it is essential in considering the incremental benefit of the Plan to recognize that continued safe, reliable service from the eligible investments in the Plan be compared against the potential for service deterioration and capacity restraint that would occur if these investments were not made. Mr. Bull testified that while the Plan addresses all four types of eligible investment in the TDSIC Statute, most of the Plan's investments positively impact public safety. He stated 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 or curtailments driven from the inability to maintain gas system pressure during peak load events; and system modernization impacts both safety and reliability by upgrading the facilities to current industry standards. He noted that the Plan also extends the benefit of natural gas service to rural areas.

~~Although~~ OUCC witness Mr. Krieger testified that <u>although</u> NIPSCO identified the cost of the projects and demonstrated the benefits of the TDSIC Plan through the reduction of risk, ~~he recommended that the Commission deny NIPSCO's application because~~ NIPSCO has not quantified the reduced risk associated with completion of projects in comparison to other projects not included. ~~We disagree. Although in Cause No. 45264 IPL was able to monetize the value of avoiding service outages associated with asset failure from the customer experience perspective for some of its proposed projects, that analysis did not attempt to quantify all project benefits, but rather focused on projects that lent themselves readily to monetization. Such an analysis in this Cause would be very difficult without attempting to (a) assign a dollar value to the health and safety of NIPSCO's customers individually or in the aggregate, or (b) evaluate the economic impact of a gas outage on the enormous number of industrial customers served by NIPSCO's system. There is nothing in the TDSIC Statute that would indicate that such an analysis is necessary.~~

The record evidence demonstrates that NIPSCO's TDSIC Plan is proposed to reduce risk of asset failure and maintain service reliability. In doing so, the TDSIC Plan provides incremental benefits compared to how the future would otherwise unfold. <u>In addition, the determination of best estimates above results in a significant decrease to the total costs proposed by NIPSCO, thereby improving the balance for purposes of the cost-benefit analysis.</u>

Accordingly, ~~based on the evidence presented, we find that NIPSCO has sufficiently prioritized and optimized the incremental benefits of its Plan and otherwise shown a sound basis for the proposed projects and associated costs, which is consistent with the standard we have previously applied to the evaluation of incremental benefits under the TDSIC Statute.~~

~~Therefore,~~ the Commission concludes~~'s determination is~~ that the estimated costs of NIPSCO's TDSIC Plan improvements, as modified herein, are justified by incremental benefits attributable to the TDSIC Plan.

G. NIPSCO's TDSIC Plan Is Reasonable. As discussed above, NIPSCO's TDSIC Plan, as modified herein, satisfies the applicable statutory requirements. The TDSIC Plan, as modified, is reasonably designed to incrementally maintain or improve safety, NIPSCO's ability to serve its customers, and the reliability and resiliency of NIPSCO's system. The Plan also includes the extension of gas facilities into rural areas. The record establishes that NIPSCO's Plan, as modified, is based on a logical approach and sound analysis ~~that presents~~using the best estimate of the cost of the investments as determined herein. Accordingly, based upon our review of the evidence of record and the foregoing considerations of each component of Ind. Code§ 8-1-39-10, we find that NIPSCO's TDSIC Plan, as modified herein, is reasonable and is therefore approved. In accordance with Ind. Code § 8-1-39-l0(b), we authorize TDSIC treatment for the improvements described in NIPSCO's TDSIC Plan, including costs incurred prior to the date of this Order that were discussed by Ms. Becker, as set forth in this Order.

H. Plan Development Costs and PS&I Costs. To demonstrate compliance with the TDSIC Statute, IPL was required to perform risk modeling and planning showing that the TDSIC Statute criteria are satisfied. NIPSCO hired independent consultants to support this effort, including PFES, LLC and TRC Companies, Inc. As stated above, NIPSCO seeks Commission approval to defer and recover these costs with approximately $1.5 million of Plan development costs to be amortized over the life of the Plan as capital overhead (or indirect capital), which is consistent with how NIPSCO allocated plan development costs in its Gas Plan 1.

No party presented evidence challenging the amount or recovery of NIPSCO's plan development and PS&I costs. We find and conclude that NIPSCO's proposal is reasonable and is approved.

I. Accounting and Ratemaking. As summarized above, NIPSCO requests Commission approval to defer TDSIC costs until they are recovered through the TDSIC adjustment factor or included in basic rates. Mr. Racher testified that NIPSCO seeks Commission authority to recover approved capital expenditures and TDSIC costs through its existing approved Gas TDSIC Mechanism. The Commission approved NIPSCO's Gas TDSIC Mechanism in its TDSIC-1 Order, allowing for the timely recovery of 80% of eligible and approved capital expenditures and TDSIC costs and authorization to defer, until recovery through the TDSIC, 80% of the post in service TDSIC costs of the TDSIC project, including carrying costs, depreciation and taxes.

NIPSCO witness Mr. Racher testified the only change NIPSCO is proposing to its accounting and ratemaking authority is to adjust its allocation percentages to reflect the significant migration of customers amongst the various rate classes for each TDSIC tracker filing to prevent any unintended consequences of the migration of customers between rates and to properly allocate the associated share of the revenue requirement.

No party presented evidence challenging this requested relief. We find NIPSCO's migration proposal is reasonable, and is approved.

Additional issues related to accounting and ratemaking are discussed further below.

i. Calculation of Indirect Capital Costs and AFUDC. As set forth above, we find that indirect capital shall be limited to 10.94% of the capital cost, and AFUDC shall be limited to 2.5% of capital cost.

ii. Determination of Pretax Return. OUCC witness Mr. Grosskopf recommended that in a future tracker filing the Commission should consider adjustments to the WACC proposed by NIPSCO when determining the pretax return to be used for TDSIC purposes. Industrial Group witness Mr. Phillips recommended that the pretax return for TDSIC purposes should be significantly lower, to reflect the reduction in risk arising from preapproved rate recovery for rate base investments. Mr. Phillips stated that the allowed return for TDSIC purposes should recognize that NIPSCO proposes to continue to collect return in base rates associated with removed assets while also adding incremental return under the TDSIC tracker for replacement assets performing the same functions.

In a 2015 appellate decision reviewing the order in Cause No. 44371, the Court of Appeals addressed the issue of duplicative recovery under the TDSIC mechanism with respect to replaced assets. *See NIPSCO Indus. Grp. v. N Ind Pub. Serv. Co.*, 31 N.E.3d 1, 10-13 (Ind. Ct. App. 2015). While indicating that the issue raised "significant concerns," the Court concluded that the TDSIC statute did not expressly require "netting" of return to reduce the costs subject to TDSIC recovery. *Id.* at 13. At the same time, however, the Court pointed out that Ind. Code §8-1-39-13 authorizes the Commission to consider "other information" when determining a pretax return for TDSIC purposes, and indicated that provision would be an appropriate avenue to address the issue. *Id.* at 12 ("The statute does, however, allow the Commission to consider '[o]ther information that the commission determines is necessary' in calculating pretax returns.") (*citing* Ind. Code § 8-1-39-13); *id.* at 13 ("The Commission could, under this statute, address the OUCC's concern, however, it is not *required* to do so.") (emphasis in original).

NIPSCO, in its proposed order in this case, cited our discussion in Cause No. 44371 in support of its positon that no adjustment to its WACC was necessary. However, in making its argument, it failed to note the subsequent history of the appeal. The Court of Appeals, in reversing the Commission's Order in Cause No. 44371, agreed that while the TDSIC statute does not require netting, the statutory language supports the position taken by the Industrial Group here: that if the Commission chooses not to support netting of replaced assets, an adjustment to the pretax return of the utility would be appropriate.

Further, in Cause No. 45264, the Commission noted that modifications to the authorized return on equity would be appropriate for consideration in IPL's first TDSIC tracker proceeding. *IPL*, Cause No. 45264 at 27 (IURC March 4, 2020):

> Although we have consistently concluded that the TDSIC statute does not allow for the netting of retired assets as advocated by the OUCC, we note that we also found in our February 17, 2014 Order in Cause No. 44371, at p. 17, that the TDSIC statute "does not preclude us from increasing or decreasing the allowed return on equity [which is used in determining the utility's weighted average cost of capital], as the

Commission is authorized to consider other necessary information in determin[ing] the appropriate pretax return." Based on the passage of time and the experience we have gained implementing the TDSIC statute over the past six years, as well as the OUCC's continued concerns with double recovery and the Industrial Group's concerns with the shifting of risks based on plan approval, we find it appropriate to explore a reasonable adjustment under the statutory provisions.

Id.

Like IPL, NIPSCO had a recent base rate proceeding. However, given the concerns raised with double counting plant recovery and the overall risk reduction provided by statutory mechanisms on substantial TDSIC investments, as well as other tracked expenses, we find that reasonable adjustments to NIPSCO's approved WACC shall be considered in the first TDSIC tracker proceeding following approval of this Order.

~~**i. Calculation of Indirect Capital Costs and AFUDC.** Industrial Group witness Mr. Phillips proposed NIPSCO calculate indirect capital at the most recent 5-year period average of 10.94% and AFUDC at the most recent 5-year period average of 2.5%. On rebuttal, Mr. Racher explained that NIPSCO reviewed its experience in Gas Plan 1 but did not use a historic average but instead gave more weight to the recent 12.9% 2019 results while also using forward looking estimates. Mr. Racher stated that using this information as a guide, NIPSCO estimated 13.5% for indirect capital costs and increased the AFUDC estimate to 3.5% to account for the large multi-year gas transmission projects which will accrue AFUDC during the duration of the project. Mr. Racher testified NIPSCO's estimates of indirect capital and AFUDC are part of its "best estimate" of the cost of the gas transmission, distribution, and storage system investments included in the Plan. We also point out that when a calendar year is complete, the indirect capital and AFUDC amounts are updated to reflect actual costs in the appropriate TDSIC tracker filing. We find NIPSCO's proposal is reasonable, and is approved.~~

~~**ii. Determination of Pretax Return.** OUCC witness Mr. Grosskopf recommended that adjustments to the WACC based on other information when determining the pretax return used be considered in a future TDSIC tracker filing. As Mr. Racher explained, the Commission has already granted NIPSCO its ratemaking authority for its TDSIC in its TDSIC-1 Order. NIPSCO has followed that ratemaking authority in each of its update filings and, with the exception of allocators, is not requesting any changes to its ratemaking authority in this proceeding. We also point out that Ind. Code § 8-1-39-13 for determination of pretax return for NIPSCO's recent TDSIC filings was recently considered in our October 16, 2019 Order in Cause No. 44403-TDSIC-10. Thus, we decline to adopt Mr. Grosskopf's recommendation to address adjusting the WACC based on other information when determining the pretax return used in a future TDSIC tracker filing.~~

~~Industrial Group witness Mr. Phillips recommended that the pretax return for TDSIC purposes should be significantly lower, to reflect the reduction in risk arising from preapproved rate recovery for rate base investments. As Mr. Racher explained, the Commission approved a fair pretax return methodology in NIPSCO's most recent gas rate case in our September 19, 2018 Order in Cause No. 44988, in which the Industrial Group participated. In our February 17, 2014~~

~~Order in Cause No. 44371 (at 17), we noted that "NIPSCO's authorized return on equity of 10.2% was approved relatively recently in our 43969 Order on December 21, 2011. Further, we acknowledge the offsetting effects of [the TDSIC] tracker's cost recovery security and timeliness and the increased investment being made for the associated projects. Consistent with our finding above on the appropriate capital structure, we decline to lower NIPSCO's authorized return on equity from that approved in its most recent case." Given that the return determination in NIPSCO's most recent gas rate case was also approved relatively recently, and given that the TDSIC investments are new, we find that a lower return should not be included in the return on those assets.~~

~~**iii. Replaced Asset Investment Costs.** Mr. Phillips recommended that the allowed return for TDSIC purposes should recognize that NIPSCO proposes to continue to collect return in base rates associated with removed assets while also adding incremental return under the TDSIC tracker for replacement assets performing the same functions. In our February 17, 2014 Order in Cause No. 44371 (p. 18), we found:[17]~~

> ~~The statutory definition of eligible improvements at Ind. Code § 8-1-39-2 authorizes recovery of investment for replacement projects and the definition of pretax return at Ind. Code § 8-1-39-3 provides that revenues should provide for such investments, notably without suggesting any deduction or netting of the replaced asset. Further, TDSIC costs as defined at Ind. Code § 8-1-39-7 includes this unadjusted pretax return. While acknowledging that Ind. Code § 8-1-39-13(a) allows the Commission to consider other information in setting the appropriate pretax return, we read this section to be addressing the weighted cost of capital rate rather than the investment amount so as to reconcile the statutory language of Section 13 and 3. Accordingly, we do not find statutory support for the netting of investment in determining the appropriate investment to be afforded cost recovery. In addition, the TDSIC statute requires a general rate case before the expiration of the utility's 7-year plan which provides a built in mechanism to update the net investment of the utility. Thus, we decline to require NIPSCO to recognize the replaced asset investment cost already embedded in base rates because Ind. Code ch. 8-1-39 does not support it outside the required rate case.~~

~~On rebuttal, Mr. Racher testified (1) NIPSCO's projects included in the TDSIC Plan are considered eligible improvements as defined in Ind. Code§ 8-1-39-2, (2) NIPSCO's next gas general rate case will include a review of all costs (both capital and related expenses) associated with NIPSCO's TDSIC and all other gas investments, and (3) NIPSCO will file another gas general rate case prior to the expiration of the TDSIC Plan in compliance with Code§ 8-1-39-9(e).~~

~~We continue to find no statutory support for the netting of investment in determining the appropriate level of cost recovery. In addition, the TDSIC Statute requires a general rate case before the expiration of the utility's TDSIC plan which provides a built in mechanism to update the net investment of the utility. Thus, we again decline to require NIPSCO to recognize the~~

~~[17] *See also* Order on Reconsideration dated May 7, 2014, Finding No. 5.~~

~~replaced asset investment cost already embedded in base rates because Ind. Code ch. 8-1-39 does not support it outside the required rate case.~~

9. Other Matters.

A. Plan Update Process. Ind. Code§ 8-1-39-9(b) provides that a utility shall update its TDSIC Plan at least annually. NIPSCO anticipates filing a new petition every six months, and each semi-annual filing will include an update to the Plan supported by information on the actual costs incurred, a description of any moves between project years, and explanations of all increases that exceed the greater of $100,000 or 20%. NIPSCO will provide an updated Risk Model (Confidential Appendix 1) and updated unit costs (Confidential Appendix 3) included in the 2020-2025 Gas Plan as new relevant information becomes available during the Plan update process.

Ms. Becker stated that the only changes to its Plan update Process is that NIPSCO is not intending to provide the six pages comparing the approved plan to the updated plan in its current Plan Update process, including identification of the related variances because the comparisons by project category currently found on Update Pages 21, 23, and 25 can already be found on Update Page 1. No party presented evidence challenging this requested relief. We find NIPSCO's proposed update process is reasonable, and is approved. Nothing in this grant of approval for the proposed Update process, however, should be construed as waiving or modifying the requirements of Ind. Code § 8-1-39-9(g) with respect to the standard and process for seeking rate recovery of costs and expenditures in excess of approved amounts.

OUCC witness Mr. Krieger recommended NIPSCO (1) inform the OUCC if it anticipates a project will exceed the approved best estimate by greater than 20% or $100,000, and supply reasons with estimated costs for those overages, thus creating a new best estimate request for approval; and (2) supply reasons substantiated with actual costs incurred if a project's actual costs exceed an approved best estimate by greater than 20% or $100,000, both of which NIPSCO currently provides and agreed to continue to provide. Mr. Krieger also recommended that NIPSCO provide refined project location and work order level cost estimates for Plan projects originally submitted on a per unit basis, to which NIPSCO agreed to provide updated best estimates to projects that are unit based when new relevant information is available; and, to the extent that projects are initially estimated on a unit cost basis and later developed based on a project-specific basis, NIPSCO will continue to provide detailed information to support the detailed estimate.

Mr. Krieger also recommended that NIPSCO (1) provide 20-year margin tests for defined rural extensions projects including work order level costs, customers, and estimated consumption, and (2) continue to work with the OUCC to ensure the accounting process is well understood so no project costs are double counted. NIPSCO responded it is committed to working with its stakeholders to determine additional information that can be provided for rural extension projects. Mr. Bull stated NIPSCO has the ability to provide margin test results for identified projects that are included in the Plan, and rural extension project work orders are currently included in a list that NIPSCO currently provides to the OUCC from which invoice-level detail is requested to audit as part of each Plan Update filing. NIPSCO agreed to continue to work with the OUCC to ensure the accounting process is well understood so no project costs are double counted. We find the level of detail provided by NIPSCO is sufficient and encourage the parties to continue to work together to determine how to provide appropriate information for the OUCC to review Plan updates in a manner that is not unduly burdensome.

In our January 28, 2015 Order in Cause No. 44403-TDSIC-1, at pp. 25-26, we approved a credit mechanism proposed by NIPSCO for rural extensions by which 80% of actual margins associated with new rural customers are credited against rural extension costs collected through the TDSIC tracker. NIPSCO utilized that credit mechanism throughout the period that Gas Plan I was in effect. In this proceeding, NIPSCO confirmed that it proposes to continue with that credit mechanism. No party opposed that proposal. The Commission therefore approves the continued use of the rural extension credit mechanism as previously approved in Cause No. 44403-TDSIC-1.

B. Confidentiality. NIPSCO filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information on December 31, 2019, which was supported by the affidavit of Mr. Bull, showing that certain information to be submitted to the Commission were trade secrets under Ind. Code § 24-2-3-2. The Presiding Officers issued a Docket Entry on January 16, 2020 finding such information to be preliminarily confidential, after which such information was submitted under seal. After reviewing the information, we find this information qualifies as confidential trade secret information pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2. This information shall be held as confidential and protected from public access and disclosure by the Commission and is exempted from the public access requirements contained in Ind. Code §§ 8-1-2-29 and 5-14-3-4.

10. Conclusion. We find that NIPSCO's TDSIC Plan, as modified, meets the requirements of the TDSIC Statute. However, as required by the TDSIC Statute, NIPSCO will be required to provide specific justification for the Commission to approve the recovery of costs in excess of approved estimates.

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

1. The projects identified in NIPSCO's 2020-2025 Gas Plan constitute "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code § 8-1-39-2.~~;~~

2. NIPSCO's 2020-2025 Gas Plan is reasonable and approved, as modified herein.~~;~~

3. NIPSCO's extension of service in rural areas of its authorized service territory pursuant to Ind. Code § 8-1-39-11(c) is approved, as set forth herein.~~;~~

4. NIPSCO's continued used of definitions of key terms for purposes of interpreting Ind. Cod ch. 8-1-39 are hereby approved.~~;~~

5. NIPSCO is authorized to defer costs associated with the 2020-2025 Gas Plan that are incurred prior to and subsequent to the issuance of an Order in this proceeding until such amounts are recovered through rates, as set forth herein.~~;~~

6. NIPSCO's proposed process for updating the 2020-2025 Gas Plan in future TDSIC

semi-annual adjustment proceedings under the Cause No. 44403 TDSIC X is approved, as set forth herein~~; and~~.

7. The information filed by NIPSCO in this Cause pursuant to its Motion for Protective Order is deemed confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

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

HUSTON, FREEMAN, KREVDA, OBER, AND ZIEGNER CONCUR:
APPROVED:

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

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Mary M. Becerra
Secretary of the Commission