ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda	√		
Ober	√		
Ziegner	√		

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC FOR (1) APPROVAL OF AN ADJUSTMENT TO ITS GAS SERVICE RATES THROUGH ITS TRANSMISSION, DISTRIBUTION, AND STORAGE SYSTEM IMPROVEMENT CHARGE ("TDSIC") RATE SCHEDULE; (2) AUTHORITY TO DEFER 20% OF THE APPROVED CAPITAL EXPENDITURES AND TDSIC COSTS FOR RECOVERY IN PETITIONER'S NEXT GENERAL RATE CASE; (3) APPROVAL OF PETITIONER'S UPDATED 2020-2025 TDSIC PLAN, INCLUDING ACTUAL AND PROPOSED ESTIMATED CAPITAL EXPENDITURES AND TDSIC COSTS THAT EXCEED THE APPROVED AMOUNTS IN CAUSE NO. 45330, AND (4) AUTHORITY TO MODIFY THE RATEMAKING TREATMENT AUTHORIZED IN CAUSE NO. 45330, ALL PURSUANT TO IND. CODE § 8-1-39-9	)	**CAUSE NO. 45330 TDSIC 1** **APPROVED: DEC 23 2020**

ORDER OF THE COMMISSION

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

On August 25, 2020, Northern Indiana Public Service Company LLC ("Petitioner" or "NIPSCO") filed its Verified Petition with the Indiana Utility Regulatory Commission ("Commission") for approval of a new Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") pursuant to Indiana Code § 8-1-39-9. On the same date, Petitioner filed testimony and exhibits, subsequently corrected on September 8, 2020, on behalf of the following:

- Alison M. Becker, Manager of Regulatory Policy for NIPSCO;
- Elizabeth A. Dousias, Manager of Regulatory for NiSource Corporate Services Company ("NCSC");
- Ryan T. Carr, Manager of Gas TDSIC E&C Program for NIPSCO; and
- Vincent V. Rea, Director of Regulatory Finance and Economics for NCSC.

On October 13, 2020, NIPSCO Industrial Group ("Industrial Group") filed an Unopposed Petition to Intervene, which was subsequently granted on October 21, 2020.[1]

On October 27, 2020, Industrial Group filed the testimony and exhibits of Michael P. Gorman, a Managing Principal of Brubaker & Associates, Inc., consultants in the areas of energy, economics, and regulations.

Additionally, on October 27, 2020, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the testimony and exhibits of the following:

- Mark H. Grosskopf, a Senior Utility Analyst in the Natural Gas Division;
- Brien R. Krieger, a Utility Analyst in the Natural Gas Division; and
- Leja D. Courter, Director of the Natural Gas Division.

On November 13, 2020, Petitioner filed the rebuttal testimony of Ms. Dousias and Mr. Rea.

The Commission noticed this matter for an evidentiary hearing at 9:30 a.m. on November 23, 2020, in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. A Docket Entry was issued on November 18, 2020, advising that in accordance with Indiana Governor Holcomb's Executive Orders related to the COVID-19 pandemic, which provide for alternative procedures during this time of public health emergency, the hearing would be conducted via video conference and providing related information. Petitioner, the OUCC, and Industrial Group, by counsel, participated in the evidentiary hearing via video conference, and the testimony and exhibits of Petitioner, the OUCC, and Industrial Group were admitted without objection.

Based on the applicable law and evidence presented, the Commission now finds:

1. Notice and Jurisdiction. Notice of the hearing in this Cause was given and published by the Commission as required by law. Petitioner is a public utility as that term is defined in Indiana Code §§ 8-1-2-1(a) and 8-1-39-4. Under Indiana Code ch. 8-1-39 ("TDSIC Statute"), the Commission has jurisdiction over a public utility's seven-year 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. Petitioner is a public utility organized and existing under the laws of Indiana, with its principal office at 801 E. 86th Avenue, Merrillville, Indiana. Petitioner is engaged in rendering electric and gas public utility service in Indiana and owns, operates, manages, and controls, among other things, plant and equipment in Indiana used for the generation, transmission, distribution, and furnishing of such services to the public. Petitioner

[1] On October 19, 2020, Industrial Group filed an Amended Appendix A of its Petition to Intervene, expanding its listed members. The six members of Industrial Group in this proceeding, as amended, are ArcelorMittal USA, Fiat Chrysler Automotive, General Motors LLC, Praxair, Inc., United States Steel Corporation, and USG Corporation.

provides gas utility service to approximately 835,000 residential, commercial, and industrial gas customers in northern Indiana.

3. **Background and Relief Requested.** On July 22, 2020, the Commission issued an Order in Cause No. 45330 ("45330 Order") approving NIPSCO's six-year TDSIC Plan. In this TDSIC tracker filing, NIPSCO requests that the Commission: (1) approve an adjustment to its gas rates effective January 1, 2021, for the recovery of TDSIC capital expenditures and TDSIC costs incurred through June 30, 2020; (2) authorize NIPSCO to defer as a regulatory asset 20% of total capital expenditures and TDSIC costs and record ongoing carrying charges based on the current overall weighted average cost of capital ("WACC") on all deferred TDSIC costs until such costs are included for recovery in base rates; (3) approve NIPSCO's updated Plan ("Plan Update-1"), including actual and proposed estimated capital expenditures and TDSIC costs that exceed the amounts previously approved; (4) approve deferral and recovery of 80% of eligible and approved capital expenditures and TDSIC costs in connection with the updated Plan through the TDSIC and deferral of 20% of eligible and approved capital expenditures and TDSIC costs in connection with the updated Plan, for recovery in its base rates; and (5) modify the ratemaking authority granted in the 45330 Order.

4. **Evidence Presented.**

A. **Petitioner Case-In-Chief.** Ms. Alison Becker testified Petitioner is requesting approval of Plan Update-1, which includes: (1) the actual capital expenditures incurred through June 30, 2020; (2) updated cost estimates for the projects designated in Plan Update-1, including actual and proposed estimated capital expenditures; and (3) TDSIC costs that exceed the amounts approved in the 45330 Order.

Ms. Becker testified all of the TDSIC projects included for recovery in this filing were or would be undertaken for the purpose of safety, reliability, system modernization, or economic development, and Rural Extension projects were undertaken for the purpose of extending gas service in rural areas. She testified that none of these projects were included in Petitioner's rate base in Cause No. 44988, which changed Petitioner's basic rates and charges in its Order on September 19, 2018 ("44988 Order"). She stated Petitioner is requesting approval of all projects designated in Plan Update-1 that are included for recovery in the proposed TDSIC 1 factors. Ms. Becker testified Petitioner intends to petition the Commission for review and approval of its basic rates and charges prior to the expiration of its approved six-year TDSIC Plan in compliance with Indiana Code § 8-1-39-9(e).

Ms. Becker explained that to date Petitioner has not undertaken any Targeted Economic Development Projects that are eligible for recovery through the 2020-2025 TDSIC Plan. However, Petitioner continues to work with interested parties on potential projects. She further testified that in the 45330 Order, the Commission approved Petitioner's proposal to include all rural customers in the updated estimate and to provide an 80% credit to the TDSIC tracker for actual margin received from new customers added under the Rural Extension projects.

Ms. Becker testified that Petitioner met with the OUCC and interested stakeholders, including representatives of Industrial Group, on July 30, 2020. During that meeting, Petitioner identified known changes to projects approved in the 2020-2025 TDSIC Plan and issues related to this proceeding.

Ms. Becker testified that consistent with 45330 Order approving Petitioner's 2020-2025 TDSIC Plan and deferring a determination of the applicable pre-tax return to obtain additional evidence, Petitioner proposes to use 10.70% as the return on equity ("ROE") in the calculation of the pre-tax return for use in its TDSIC Plan Update filings. Regarding Petitioner's proposed ratemaking treatment, Ms. Elizabeth Dousias testified Petitioner requests authority to earn a return of $91,216,400 for the eligible improvements. This amount includes allowance for funds used during construction ("AFUDC") and other indirect costs, and the amount is net of accumulated depreciation incurred through June 30, 2020.

Ms. Dousias provided an overview of the indirect capital costs that are associated with capital projects, which must be capitalized to comply with Generally Accepted Accounting Principles ("GAAP"). She noted these often cannot be charged directly to a specific capital project work order because they cannot be directly linked to one project and tend to be incurred away from the job site. She stated that indirect capital costs fall into three categories: (1) overheads; (2) stores, freight, and handling; and (3) AFUDC.

Ms. Dousias testified that Petitioner computes AFUDC amounts and relevant AFUDC rates for the eligible improvements in accordance with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts and is also consistent with GAAP. Petitioner also has a process to ensure that AFUDC is no longer recorded after such costs are given construction work in progress ("CWIP") ratemaking treatment, are otherwise reflected in base gas rates, or the project is placed in-service, whichever occurs first. After the in-service date, Petitioner will calculate and include for recovery post in-service carrying charges on costs which have been placed into service and are not receiving ratemaking treatment until such costs receive CWIP ratemaking treatment, or are otherwise reflect in base gas rates. Ms. Dousias testified Petitioner has calculated the depreciation expense related to TDSIC capital expenditures according to each asset's designated FERC account classification. Each asset, upon being placed in-service, is depreciated by Petitioner according to the associated FERC account composite remaining life approved by the 44988 Order.

Ms. Dousias explained the calculation of Petitioner's "return on" portion of the revenue requirement for costs of the eligible improvements incurred through June 30, 2020. She stated the annual revenue requirement for the return on investment is calculated by multiplying the June 30, 2020 net book value of all TDSIC projects by the debt and equity components of Petitioner's WACC. The product of this calculation is then multiplied by 6/12 to calculate a six-month revenue requirement for this filing. This amount is then multiplied by the revenue conversion factor and further reduced to 80% to determine the total return-related revenue requirement to be recovered for bills rendered for January through June 2020, not to exceed an average aggregate increase in Petitioner's total retail revenues of more than 2% in a 12-month period.

Ms. Dousias provided the computation of the revenue conversion factor used to compute Petitioner's pre-tax revenue requirement. She testified that the revenue conversion factor is calculated for debt and equity to properly synchronize interest for the purpose of calculating the revenue requirement. The state income tax rate used in this computation was determined in accordance with Indiana Code § 6-3-2-1.

Ms. Dousias testified Petitioner is proposing to include projected depreciation and property tax expenses to reduce the regulatory lag recovering the same costs on a historical basis. She stated the projected expenses will also be reconciled in a future filing to actual amounts and Petitioner will appropriately recover or pass back the variance to customers based on actual expenses incurred.

Ms. Dousias provided information regarding actual depreciation expense and property taxes for January through June 2020, projected depreciation expense and property taxes for January through June 2021, and the prior period variance for the projected period. She explained that since there were no projections included in the prior filing, there is no variance in this filing. The expenses and taxes incurred were reduced to 80% to determine the proposed revenue requirement to be recovered for bills rendered for January through June 2021, not to exceed the 2% excess revenue test.

Ms. Dousias testified the 45330 Order approved Petitioner's proposal to provide an 80% credit to the TDSIC tracker for actual margins received from all new customers added under the Rural Extension projects. She stated these amounts are calculated by obtaining the related customer usage values and billing rate information to compute the total margin billed for January through June 2020.

Ms. Dousias explained that the revenue requirement calculated in Cause No. 44403 TDSIC 10 is being reconciled against the actual revenues received from the customers during November 2019 through May 2020, which resulted in an under-recovery of $152,656.

Ms. Dousias provided the allocation factors as approved in the 44988 Order, which Petitioner used to allocate the related transmission, distribution, and storage revenue requirements. She also explained the calculation of the TDSIC Factors by rate code based on the previously calculated revenue requirements.

Ms. Dousias testified no amount exceeded 2% of retail revenues for the past 12 months. She testified Petitioner has calculated the 2% cap by comparing the increase in TDSIC revenues with the total retail revenues for the past 12 months. The retail revenues used in this calculation represent the revenues related to the 12 months ending June 30, 2020.

Ms. Dousias noted that in the 45330 Order, the Commission authorized Petitioner to defer 20% of the TDSIC costs incurred in connection with approved eligible improvements, including ongoing carrying charges based on the current overall WACC, and recover those deferred costs in base rates. Accordingly, Petitioner has deferred as a regulatory asset 20% of all TDSIC costs resulting from the deferral of 20% of all TDSIC costs for recovery in its base rate case. Ms. Dousias concluded the estimated average monthly bill impact for a typical residential customer using 69 therms per month is a charge of $0.39, which is a $0.92 increase from the factor currently in effect.

Mr. Ryan Carr testified that the total gross direct capital expenditures associated with Petitioner's designated eligible improvements as of December 31, 2019, relating to TDSIC Plan 1, are $58.0 million and the total indirect capital expenditures are $7.0 million. Mr. Carr testified the total AFUDC for capital expenditures is $1.0 million. The total gross direct capital expenditures associated with Petitioner's designated eligible improvements as of June 30, 2020, relating to the 2020-2025 TDSIC Plan are $22.1 million. He stated that the total indirect capital expenditures associated with NIPSCO TDSIC investments are $3.6 million and the total AFUDC is $0.328 million.

Mr. Carr stated that there may be differences in the transmission and distribution subtotals when comparing project category to FERC account. He explained that some projects, such as inspect and mitigate projects, may incur charges that are booked to both distribution and transmission FERC accounts. However, because most project costs related to specific projects are charged to either distribution or transmission FERC accounts, the project is classified into either a transmission or distribution project category on Plan Update-1 and related schedules.

Mr. Carr noted that in the 45330 Order, the Commission approved Petitioner's proposal to: (1) include all Rural Extension projects, both those that qualify using the 20-year margin test under Indiana Code § 8-1-39-11 and those that may qualify under Petitioner's existing line-extension policy; and (2) provide an 80% credit to the TDSIC tracker for actual margins received from all new customers added under Rural Extension projects. He stated the forecast in the 2020-2025 TDSIC Plan are the costs associated with designing and installing gas main and service projects to reach rural areas and explained how Petitioner administers the Rural Extension projects. He testified Rural Extensions included in Plan Update-1 are projected to pass the 20-year test identified in Indiana Code § 8-1-39-11.

Mr. Carr testified Plan Update-1 reflects current cost estimates for the completion of the projects in the 2020-2025 TDSIC Plan. He stated that for projects scheduled for completion in 2020, the estimated costs are based on final or near final engineering and updated unit costs or current bids. For projects scheduled for completion in 2021, estimates are based on unit costs or costs based on actual experience.

Mr. Carr testified Plan Update-1 includes two new projects that were not described in its 2020-2025 TDSIC Plan: (1) Project ID IM41 – Arcelor Mittal Station #1 in 2021 ("IM41"); and (2) Project ID IM42 – Arcelor Mittal Station #2 in 2023 ("IM42"). He explained that the Arcelor stations were evaluated through Petitioner's Safety Management System ("SMS") and deemed priority projects to reduce the risk to Petitioner's system, but were not included in the 2020-2025 TDSIC Plan because the events that prompted them to be included had not occurred yet. He described the projects and the costs.

Mr. Carr showed the total projected capital spending, including indirect capital costs and AFUDC, for Plan Update-1 compared to the 2020-2025 TDSIC Plan, as follows:

	2020	2021	2022	2023	2024	2025	Plan Total
Approved Plan	$83,860,906	$120,859,098	$177,923,716	$200,942,931	$186,174,856	$178,915,013	$948,676,520
Plan Update-1	$81,139,312	$140,305,107	$177,923,716	$209,523,501	$186,174,856	$178,915,013	$973,981,505
Variance	**($2,721,594)**	**$19,446,009**	**0**	**$8,580,570**	**0**	**0**	**$25,304,985**

Mr. Carr testified the indirect cost of 13.5% and AFUDC of 3.5% used in the 2020-2025 TDSIC Plan did not change in Plan Update-1, but the actual indirect capital costs and AFUDC costs would be included in Plan Update-1 when a given calendar year is closed out. Plan Update-1 reflects an overall decrease in direct costs in 2020 of $2,721,594. For 2020, Mr. Carr described the project costs moved into 2020 and explained three projects that drove the noteworthy cost increases. For 2021, he described the project costs moved into 2021 and described the new Arcelor Mittal Station #1 Project. For 2023, he described the new Arcelor Mittal Station #2 Project.

Mr. Carr testified Plan Update-1 includes: (1) information to support Petitioner's best estimate of the cost of investments included in the Plan, including a risk model; (2) project change requests supporting any project variance that is in excess of $30,000 or 15%, whichever is greater, or any variance that exceeds $100,000 for any project whether or not it meets the 15% threshold; (3) estimates for new Projects IM41 and IM42; and (4) a summary of unit cost estimates.

Mr. Carr testified that Plan Update-1 is intended to provide benefits in the form of investments to maintain and improve system reliability through the capacity of the system to deliver gas to customers when they need it, replacement of certain system assets to ensure the ongoing integrity and safe operation of the gas system, and the extension of gas facilities into rural areas. He testified Plan Update-1 is proposed to reduce the risk of asset failure and maintain service reliability and, in doing so, Plan Update-1 provides incremental benefits compared to how the future would otherwise unfold. He stated Rural Extensions included in Plan Update-1 would continue to increase the number of rural customers served over the life of the Plan.

Mr. Vincent Rea testified Petitioner's ROE authorized in the 44988 Order was 9.85%, which reflects the ROE that was agreed upon by the settling parties in the Stipulation and Settlement Agreement in that proceeding. He updated the cost of equity ("COE") analysis that he prepared as part of that case to provide the Commission with additional information related to the appropriate pre-tax return applicable to TDSIC investments under the TDSIC Statute, resulting in a point estimate of 10.70%.

Mr. Rea stated Petitioner's ROE should not be adjusted downward to reflect the purported risk reduction aspects of Petitioner's gas TDSIC program. He explained that the market-based data of the proxy group companies evaluated already capture any theoretical reduction in business risks that would result from the reduced regulatory lag associated with infrastructure cost recovery mechanisms; therefore, any such reduction in risk would already be reflected in the COE estimates produced by referencing the financial and market data of the proxy group companies. He stated that since equity investors do not evaluate potential investments in utility companies in isolation, but rather on a comparative basis versus other utility companies, the existence of the TDSIC program would not be expected to either increase or decrease the level of risk perceived by investors when considered on a comparative basis. He stated that in essence, Indiana's TDSIC program puts the state's utilities on an equal footing with other utilities nationwide, which also benefit from similar infrastructure cost recovery mechanisms. He also stated it is important to note that infrastructure cost recovery mechanisms ultimately serve the public interest by ensuring the safety and reliability of a utility's gas infrastructure. Mr. Rea testified applying a downward ROE adjustment would be tantamount to assessing an economic penalty on Petitioner for implementing a cost recovery program that was established by Indiana statute and ultimately serves the public interest.

Mr. Rea testified a critical takeaway from an evaluation of the risk metrics is that it is highly likely that the equity risk premium continues to remain markedly elevated in the ongoing COVID-19 environment. Mr. Rea testified the recent downward trending interest rate environment must be considered in the context of the currently elevated levels of risk and volatility due to the COVID-19 crisis, consistent with a higher equity risk premium. Mr. Rea opined that there is no question that NIPSCO's revenues, earnings, and operating cash flows have been negatively impacted by the COVID-19 crisis, which increased NIPSCO's investment risk profile.

Mr. Rea testified that it can also be argued that Petitioner's planned capital expenditures over the next six years under the TDSIC program would increase Petitioner's investment risk profile. He explained that a robust capital expenditure program such as Petitioner's could, in the absence of assured and timely cost recovery, put considerable pressure on Petitioner's cash flow and debt leverage credit metrics over the near-to-intermediate term. He noted that in the absence of mitigating factors, a company that is generating negative free cash flows will, by definition, see its investment risk profile increase. For this reason, Petitioner's ability to recover these costs in a timely manner, either through a general rate case proceeding, or through the TDSIC mechanism, is absolutely essential to maintaining Petitioner's credit metrics in the range necessary to preserve its investment grade credit ratings.

Mr. Rea also noted that there is no disputing that the TDSIC mechanism serves to accelerate the cost recovery process between rate cases and reducing regulatory lag. At the same time, the credit rating agencies have made clear that the long-term credit ratings they have assigned to Petitioner are conditioned upon the continued presence of Petitioner's existing cost recovery mechanisms, including the TDSIC program. He testified that Petitioner's credit ratings are also dependent upon its current levels of earnings and cash flows, which do not reflect a COE penalty for implementing its TDSIC Plan. Applying such a penalty would be counter-productive, since as noted above, the TDSIC is a cost recovery mechanism that supports Petitioner's credit standing and was created by Indiana statute to promote the public interest.

Mr. Rea also provided details on his update to the COE evaluation using the Discounted Cash Flow ("DCF") Model Analysis, the Capital Asset Pricing Model ("CAPM") Analysis, and the Risk Premium Analysis. Mr. Rea concluded that based on the results of his analysis, Petitioner's COE has not declined since its last rate case. He explained that his evaluation of Petitioner's COE, including consideration of the currently prevailing risks facing Petitioner, demonstrates that any adjustment to Petitioner's pre-tax return applicable to its gas TDSIC investments should be an increase to its return.

B. <u>OUCC Case-in-Chief</u>. Mr. Mark Grosskopf stated he performed a comprehensive analysis of the calculations and data flow contained in Petitioner's TDSIC rate schedules. Mr. Grosskopf explained his adjustment to the proposed TDSIC Rate Factor calculations to remove the projected depreciation and property tax expenses. He stated that Petitioner's projection of depreciation and property tax expenses seeks recovery of these expenses based, in part, on utility plant that has not been purchased, completed, or placed in-service as of the cut-off date of June 30, 2020, but rather is forecasting the utility plant it assumes it might add in a future period, which may or may not be completed before or during the recovery period. He indicated that no other utility forecasts depreciation and property tax expenses for TDSIC recovery in this manner. He noted that Indianapolis Power & Light ("IPL") and Vectren Energy Delivery of Indiana, Inc. ("Vectren") project these expenses based on the projects completed as of the cut-off date for TDSIC expenditures, making them based on fixed, known, and measurable utility-plant-in-service ("UPIS"), and enabling accurate projections.

Mr. Grosskopf explained his adjustment to the proposed TDSIC Rate Factor calculations to use Mr. Leja Courter's recommended 9.0% ROE. He stated he reviewed the calculations and flow of inputs from other schedules and Petitioner accurately calculates the TDSIC Rate Factors.

Mr. Grosskopf testified Petitioner shows the reconciliation of the revenue requirement approved in Cause No. 44403 TDSIC 10 with actual revenue collected during November 2019 through May 2020. He stated the result is an under-recovery in the amount of $152,656, which will be added to the revenue requirement to be collected from customers through the TDSIC rate calculation in this Cause. Mr. Grosskopf recommended his adjusted Rate Factors calculated on Attachment MHG-1 be approved as the new TDSIC tariff rates.

Mr. Grosskopf testified Petitioner reflects the cumulative total deferred revenue requirements, broken out by return on capital, return of expense, and carrying charges. He stated prior to the Cause No. 44403 TDSIC 10 filing, much of the deferred revenue requirements from past TDSIC filings were rolled into base rates in Step 1 and Step 2 compliance filings in Cause No. 44988. He testified the remaining deferred revenue requirements from Cause Nos. 44403 TDSIC 9, TDSIC 10, and TDSIC 11 are added to this filing's deferred revenue requirement to be deferred for recovery in Petitioner's next rate case. Mr. Grosskopf traced all data input in Petitioner's Attachment 1, Schedule 10 to the source schedules in the current and previous filings and compliance filings in Cause No. 44988, and he verified the calculations. He testified that due to the elimination of projected expenses on Petitioner's Attachment 1, Schedule 4, and the OUCC's proposed ROE, he recalculated the total deferred revenue.

Mr. Grosskopf agreed with the Rural Extension margin credit calculated on Petitioner's Attachment 1, Schedule 5. He stated the margin credit balances the interests of the utility and the ratepayers and the OUCC continues to support Petitioner's approved 80% margin credit for Rural Extensions for each TDSIC filing.

Mr. Brien Krieger discussed his analysis, conclusions, and recommendation regarding 2020-2025 project cost recovery in Petitioner's Plan Update-1. He analyzed the two new projects and three approved projects that have experienced increased actual costs as compared to approved estimates (Projects RE1, TP8, and IM37) in 2020. Mr. Krieger testified Petitioner has satisfied Indiana Code § 8-1-39-9(g) for justifying the increased costs of all approved projects and Indiana Code § 8-1-39-10(b) for qualifying the new projects as TDSIC projects. Mr. Krieger recommended the Commission approve Petitioner's Plan Update-1. He also recommended that in future TDSIC filings, Petitioner provide a Project RE1 annual summary, indicating separately estimated and actual customers for Rural Extension projects.

Mr. Courter opined that neither Petitioner's authorized 9.85% ROE from its last rate case nor its proposed 10.7% ROE in this proceeding should be used in calculating its TDSIC Factors. Mr. Courter testified that based on the results of the DCF method, CAPM, and macroeconomic analysis, a COE of 9.0% would be reasonable and appropriate. He testified that neither his DCF nor his CAPM analysis yielded a return as high as Petitioner's current 9.85%, let alone the proposed 10.7%. He stated the current economic condition nationally and in Indiana is best described as "recessionary" and data on bond yields, dividend yields, inflation, and economic growth do not support projections of double-digit rates of return. Moreover, regulated public utilities tend to be less risky than the market as a whole.

Mr. Courter testified that lower returns on equity have become more common to public utilities over the past decades, with the average for natural gas utilities for 2019 of 9.71% and the average for natural utilities for the first half of 2020 of 9.4%. He stated the annual natural gas utility average authorized ROE has been below 10% every year since 2011 and that since the beginning of 2016, the average has been above 10% only once (third quarter of 2014). Mr. Courter testified his recommendation would allow Petitioner access to capital on reasonable terms.

Mr. Courter testified he relied primarily on the DCF model and CAPM to estimate Petitioner's COE, but because NIPSCO is not publicly traded, some data is not available, and it is impractical to apply the DCF and CAPM directly to Petitioner. Therefore, he calculated Petitioner's COE based on a proxy group of publicly traded companies. He stated he used the same proxy groups as Mr. Rea. He described his resulting DCF calculations for COE as follows: (1) 9.0% for the Gas Utility Group; (2) 8.6% for the Combination Utility Group; and (3) 8.8% for the Non-Regulated Group.

Mr. Courter agreed with risk factors identified by Mr. Rea, but stated that these factors are affecting all utilities in the proxy groups, and are already considered in an efficient market and reflected in the projected growth rates, making no additional adjustment warranted. Mr. Courter stated recent trends in interest rates, inflation, and economic growth do not suggest a return to an inflationary economy and there is no indication macroeconomic trends are fueling any significant increase in capital costs, making his recommended ROE of 9.0% more in line with current economic conditions.

C. Industrial Group Case-in-Chief. Mr. Michael Gorman recommended that the Commission reject Petitioner's proposal to increase its base ROE. He stated that Petitioner's proposal does not accurately and reasonably reflect a current estimate of its capital market costs and he believes Petitioner's current market COE falls in the range of 9.0% to 9.4%.

Mr. Gorman also recommended two further adjustments to Petitioner's ROE for TDSIC purposes to address material respects in which TDSIC cost recovery differs from base rate cost recovery. He stated the TDSIC mechanism: (1) provides opportunity for double recovery associated with asset replacements; and (2) at the same time, largely eliminates the utility risk arising from base rate recovery of capital investments. He opined that double recovery and reduced risk each justify a 20-basis point reduction to the ROE for TDSIC revenue, or together a 40-basis point reduction.

As an alternative to a reduction in ROE for TDSIC, Mr. Gorman recommended a more direct method to adjust the revenue requirement to reflect net depreciation. First, he recommended the depreciation expense should reflect the increased depreciation expense with new TDSIC investments offset by embedded TDSIC Plan investments that are retired and taken out of service with the net change in Petitioner's depreciation expense reflecting depreciation expense for new plant investment less the depreciation expense recorded in base rates for retired plant. Second, he recommended a roll-forward of depreciation expense in measuring the change in net plant in-service for the TDSIC transmission, distribution, and storage facilities to ensure that total rate charges, including base rates and TDSIC charges, are just and reasonable.

Mr. Gorman recommended the rate of return for TDSIC revenue requirements be based on the marginal cost of debt. He opined that Petitioner's embedded cost of debt has been decreasing significantly over time. Mr. Gorman proposed that the Commission should require Petitioner to use its marginal cost of debt, 3.47%, rather than the 4.71% embedded cost of debt, for purposes of determining the pre-tax return for Petitioner's gas tracker. Base rates currently are designed to recover embedded interest costs that are more than Petitioner's current interest costs. TDSIC incremental revenue requirements should reflect the incremental debt cost, not the embedded debt cost. For those reasons, he recommended the TDSIC represent the average embedded debt cost for debt issued after January 1, 2021.

Finally, Mr. Gorman recommended that Petitioner's proposal to recover depreciation and property tax expenses on a projected basis should be rejected. He opined that Petitioner's proposal is contrary to its longstanding practice with the TDSIC rider, inconsistent with traditional ratemaking based on actually incurred costs, and unsupported by citation to the terms of the TDSIC Statute, which already provides measures to reduce regulatory lag without authorizing rate adjustments to recover projected costs.

D. <u>Petitioner Rebuttal</u>. In rebuttal, Ms. Dousias testified Petitioner modified its proposed TDSIC Factors in two ways: calculation of projected depreciation and property tax expenses and reduced depreciation expense.

Regarding projected depreciation and property tax expenses, Ms. Dousias stated given that the OUCC believes the approach used by the other identified utilities relying on plant as of the TDSIC cut-off date is a more accurate means of determining the expenses to be recovered for the applicable period, Petitioner has agreed to follow the approach to calculate its depreciation and property tax expenses in its TDSIC tracker filings, subject to reconciliation. She noted that the modified approach is consistent with that approved in recent IPL and Vectren Orders.[2] Ms. Dousias sponsored attachments showing the reductions to depreciation and property tax expenses.

Regarding reduced depreciation expense, Ms. Dousias stated that in response to Messrs. Grosskopf's and Gorman's "double recovery" concerns and guided by the IPL Order, Petitioner is similarly proposing a methodology to reduce the recovery of depreciation expense associated with its TDSIC Plan. She stated that given that a retirement will lag the placement in-service of a new TDSIC related asset, Petitioner is proposing using a representative and historical method that relies on a three-year average retirement rate by FERC account (the "retirement rate") to determine the depreciation reduction adjustment to be applied to its recovery of depreciation expense in its TDSIC tracker proceedings. She explained the source of this information is Petitioner's FERC Form 2.[3] The retirement rate is then applied to the amount of the TDSIC investments included in Petitioner's Exhibit 1, Attachment 1-A, Attachment 1, Schedule 1, Column N, resulting in a value determined for retirement assets by FERC account. Petitioner then applies the depreciation rates (approved in the 44988 Order) to the retirement values by FERC account to determine depreciation expense. The amount of depreciation expense represents the values to reduce the recovery of

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[2] *Indianapolis Power & Light,* Cause No. 45264 TDSIC 1, 2020 WL 6132215 (IURC Oct. 14, 2020) ("IPL Order"). *Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc.,* Cause No. 44910, 2017 WL 4232049 (Sept. 20, 2017) ("Vectren Order").

[3] In its following two tracker filings (TDSIC 3 and TDSIC 4), NIPSCO will use the FERC Form 2 that will be submitted to the Commission on April 30, 2021.

depreciation expense associated with Petitioner's TDSIC Plan. She stated use of a three-year average is reasonable, sustainable, and addresses the difficulty of identifying the precise assets retired (resulting from the lag). She testified the effect of this reduction to depreciation expense is a decrease in the revenue that would otherwise have been recovered through the TDSIC tracker, which nets depreciation expense to reflect the retirement of certain assets as a result of the TDSIC Plan. Ms. Dousias sponsored Attachment 2-R-B setting out Petitioner's calculation for this tracker filing, and she stated that using its FERC Form 2, Petitioner would update the retirement assumption rate annually after providing the FERC Form 2 to the Commission on April 30.

Ms. Dousias stated that Petitioner's methodology represents an approach grounded in Petitioner's actual historical experience to determine a reasonable retirement rate, using historical amounts in public forms submitted to the Commission. She stated Petitioner proposes to calculate the retirement depreciation expense reduction amount on both new and replacement asset values and using the capital amounts at the end of the test period, which benefits customers because the highest capital amounts during the test period are used in the calculation in lieu of using only replacement assets, ratably placed in-service, for the revenue requirement months.

In response to Mr. Gorman's proposal for a second adjustment that entails determining all changes to net plant in the FERC accounts in which TDSIC investments are recorded, Ms. Dousias stated Mr. Gorman's net plan proposal requires consideration of annual non-TDSIC related plan investments, which the TDSIC Statute does not require. She stated that Section 7 of the TDSIC Statute defines "TDSIC costs" as costs incurred with respect to eligible transmission, distribution, and storage system improvements, as defined in Section 2 of the TDSIC Statute. She stated Mr. Gorman did not explain: (1) how consideration of all net plant placed in-service is appropriate to determine recoverable TDSIC costs incurred with respect to eligible transmission, distribution, and storage system investments; or (2) how effectively requiring a rate base adjustment in a TDSIC proceeding, which is not required by the TDSIC Statue, is appropriate. Ms. Dousias noted that the Commission rejected Mr. Gorman's net plan adjustment proposal in IPL's case.

Ms. Dousias sponsored Revised Attachment 3 showing the TDSIC Factors proposed to be applicable for bills rendered for January through June 2021. She stated the estimated average monthly bill impact for a typical residential customer using 69 therms per month is a charge of \$0.32, representing an increase of \$0.85 from the factor currently in effect and representing a decrease of \$0.07 from the factor proposed in Petitioner's case-in-chief. She testified that Petitioner's revised TDSIC Factors do not result in an average aggregate increase in Petitioner's total retail revenue of more than 2% in a 12-month period.

Mr. Rea responded to the OUCC's recommended ROE of 9.0% and Industrial Group's COE recommendation in the range of 9.0% to 9.4%, and he stated that their recommendations would not allow Petitioner the opportunity to earn a fair pre-tax return on its gas TDSIC tracker. He testified 9.0% falls at the extreme lower end of recent ROE determinations for gas utilities nationwide. He stated that if the ROE recommendations of the opposing witnesses were adopted, it would send a clear message to the financial community that the regulatory climate in Indiana was not fully supportive of maintaining financially sound utilities, which could potentially have negative implications from a capital attraction standpoint. He testified the proposed ROE of the opposing witnesses is approximately 90-100 basis points lower than recent authorized ROEs granted by the Commission for several base rate proceedings in Indiana, as well as the TDSIC ROE recently granted to IPL.

Mr. Rea testified that while the opposing witnesses maintain that recently declining U.S. Treasury and utility bond yields are, by definition, an indication of a declining COE, they have failed to recognize that market volatility and investment risk continues to remain elevated in the COVID-19 environment. He stated this strongly suggests that the market equity risk premium has increased significantly since prior to the COVID-19 crisis. He stated recent monetary policy interventions of the U.S. Federal Reserve Board were designed to exert downward pressure on long-term interest rates to stimulate economy activity, the result of which does not reflect normal supply and demand dynamics in the U.S. capital markets. He stated it is not appropriate to assume that the COE has recently declined purely based on the recent downward trend in long-term interest rates.

Mr. Rea testified that the manner in which the opposing witnesses applied the DCF, CAPM and Risk Premium Method ("RPM") models caused the DCF-determined COE estimates, which range from 8.60% to 9.20%, to be understated by as much as 160- to 220-basis points the CAPM-determined COE estimates, which range from 6.42% to 9.20%, to be understated by as much as 140- to 420-basis points. He testified that Mr. Gorman's COE estimates under the RPM, which ranges from 9.0% to 9.4%, is understated by as much as 80- to 120-basis points.

Mr. Rea testified that Mr. Gorman's proposal to reduce Petitioner's TDSIC ROE by 20-basis points due to the alleged risk reducing effects of the TDSIC mechanism should be rejected for several reasons. Mr. Gorman did not recognize that many of the proxy group companies that are referenced in estimating Petitioner's COE already benefit from similar infrastructure tracking mechanisms, strongly suggesting that the capital markets have already reflected the purported risk reducing benefit of the TDSIC program into the market data of the proxy group companies. Mr. Gorman also did not consider that the sheer size and scale of Petitioner's capital expenditure plan increases Petitioner's risk profile, which has long been recognized by the rating agencies. Mr. Rea noted that the Commission previously recognized in Petitioner's 2013 TDSIC proceeding in Cause No. 44371 the offsetting effects of increased investment versus the security and timeliness of the TDSIC mechanism, and for this reason, rejected Mr. Gorman's proposal to reduce Petitioner's TDSIC ROE.

Mr. Rea testified Mr. Gorman's proposal to reference Petitioner's marginal cost of debt (rather than Petitioner's embedded cost of debt) for purposes of determining the pre-tax return for Petitioner's gas TDSIC tracker should also be rejected because Mr. Gorman's proposal is clearly inconsistent with the plain language of Indiana Code § 8-1-39-13(a), which states that when determining the pre-tax return for purposes of the TDSIC revenue requirement, the Commission may consider the public utility's capital structure and the "actual cost rates" for the public utility's long-term debt and preferred stock. In the instant proceeding, Petitioner calculated its cost of long-term debt using actual cost rates, which is in accordance with the plain language of the statute. He stated that in its IPL Order, the Commission rejected a very similar proposal made by Mr. Gorman. Mr. Rea also testified Mr. Gorman's proposal to deny a "return on" NiSource's stock issuance flotation costs should be also be rejected.

Mr. Rea testified that he found no new evidence that would cause him to modify the recommendations made in his direct testimony. He concluded that Petitioner's COE remains in the range of 10.45% to 10.95%, and that a point estimate of 10.70% provides a reasonable estimate of Petitioner's COE for purposes of determining the pre-tax return for Petitioner's gas TDSIC tracker. Therefore, to the extent that the Commission elects to refer to the "other information" clause of Indiana Code § 8-1-39-13(a)(5), in addition to the ROE authorized by the Commission in Petitioner's 2017 gas rate case proceeding, he recommended that the Commission adopt a COE of 10.70% for purposes of Petitioner's pre-tax return for Petitioner's gas TDSIC tracker.

5. Commission Discussion and Findings.

A. Compliance with Indiana Code § 8-1-39-9.

i. Indiana Code § 8-1-39-9(a). This statute, subject to subsection (d), requires that a gas public utility may file with the Commission rate schedules establishing a TDSIC that will allow the periodic automatic adjustment of the public utility's basic rates and charges to provide for timely recovery of 80% of approved capital expenditures and TDSIC costs, and Petitioner seeks the same in this proceeding. The evidence of record demonstrates that the Petition: (1) uses the customer class revenue allocation factors based on firm load approved in Petitioner's most recent retail base rate case Order; (2) includes its Commission-approved TDSIC Plan; and (3) includes the projected effects of the TDSIC Factors on retail rates and charges. Based on the evidence of record, we find that Petitioner has complied with the requirements of Indiana Code § 8-1-39-9(a).

ii. Indiana Code § 8-1-39-9(b). This statute requires that a public utility shall update its TDSIC Plan at least annually and may include a request for approval of transmission, distribution, and storage system improvement projects not described in its TDSIC Plan most recently approved by the Commission under Section 10 of the TDSIC Statute. Petitioner's TDSIC Plan was approved on July 22, 2020 Order in the 45330 Order, which approved Petitioner's proposal to update its TDSIC Plan semi-annually. Plan Update-1 describes two new projects that were not described in Petitioner's approved TDSIC Plan. Based on the evidence of record, we find that Petitioner has complied with the requirements of Indiana Code § 8-1-39-9(b).

iii. Indiana Code § 8-1-39-9(c). This statute requires that a public utility that recovers capital expenditures and TDSIC costs under subsection (a) shall defer the remaining 20% of approved capital expenditures and TDSIC costs, including depreciation, AFUDC, and post in-service carrying costs, and shall recover those capital expenditures and TDSIC costs as part of the next general rate case that the public utility files with the Commission. Petitioner proposes to defer as a regulatory asset 20% of its eligible and approved capital expenditures and TDSIC costs and record ongoing carrying charges based on the current overall WACC on all deferred TDSIC costs until such costs are included for recovery in Petitioner's next general rate case. The evidence of record demonstrates that Petitioner has reflected the revenue requirement components on an after-tax basis in the TDSIC revenue requirement as shown in Petitioner's Schedule 10, and we find that Petitioner has complied with the requirements of Indiana Code § 8-1-39-9(c).

iv. **Indiana Code § 8-1-39-9(d).** This statute requires in relevant part that Petitioner may not file a petition under subsection (a) within nine months after the date of a Commission Order changing its basic rates and charges for gas. Petitioner filed its Petition in this Cause on August 25, 2020, and its most recent rate case was decided on September 19, 2018, in the 44988 Order. Therefore, the Petition in this Cause was filed more than nine months after our most recent Order changing Petitioner's basic rates and charges and complies with Indiana Code § 8-1-39-9(d).

v. **Indiana Code § 8-1-39-9(e).** This statute requires that a public utility that implements a TDSIC under this chapter shall, before the expiration of its approved TDSIC Plan, petition the Commission for review and approval of the public utility's basic rates and charges with respect to the same type of utility service. Ms. Becker testified Petitioner intends to petition the Commission for review and approval of its basic rates and charges prior to the expiration of its approved six-year TDSIC Plan. Therefore, the Commission finds that Petitioner is in compliance with Indiana Code § 8-1-39-9(e).

vi. **Indiana Code § 8-1-39-9(f).** This statute requires that a public utility may file a petition under this section not more than one time every six months. Ms. Becker testified the last time Petitioner filed a TDSIC adjustment filing for timely recovery of its TDSIC costs was February 25, 2020. Therefore, the Commission finds Petitioner is in compliance with Indiana Code § 8-1-39-9(f).

vii. **Indiana Code § 8-1-39-9(g).** This statute requires actual capital expenditures and TDSIC costs that exceed the approved capital expenditure and TDSIC costs must be specifically justified by the public utility and specific approval by the Commission before being authorized for recovery in customer rates. Petitioner provided the total actual capital expenditures and TDSIC costs that exceed the approved capital expenditures and TDSIC costs associated with Petitioner's TDSIC Plan as of the June 30, 2020 cutoff date for this filing and described the projects. Petitioner also provided the in-service costs for the TDSIC projects placed into service by June 30, 2020, as well as the CWIP costs for the TDSIC projects not placed into service by June 30, 2020. We have previously found that plan updates should include a discussion of any changes in an eligible improvement's best estimate of cost, necessity, and associated incremental benefits upon which the Commission based its determination to approve Petitioner's proposed Plan as reasonable, and a discussion of pertinent issues follows:

1. **Cost Estimates.** Mr. Carr testified Plan Update-1 reflects current cost estimates for the completion of the projects in the TDSIC Plan. He stated that for projects scheduled for completion in 2020, the estimated costs are based on final or near final engineering and updated unit costs or current bids. For projects scheduled for completion in 2021, estimates are based on unit costs or costs based on actual experience. Mr. Carr testified Plan Update-1 includes two new projects that were not described in its approved TDSIC Plan: Projects IM41 and IM42; and he described both projects and explained the estimate development.

Mr. Carr testified Plan Update-1 reflects an overall decrease in direct costs in 2020. For 2020, Mr. Carr described the project costs moved into 2020 and explained three projects that drove the noteworthy cost increases. For 2021, he described the project costs moved into 2021 and described the new Arcelor Mittal Station #1 project. For 2023, he described the new Arcelor Mittal Station #2 project.

Mr. Carr testified Plan Update-1 provides information to support Petitioner's best estimate of the cost of investments in the Plan, including: (1) a risk model in Confidential Appendix 1; (2) project change requests supporting any project variance that is in excess of $30,000 or 15%, whichever is greater, or any variance that exceeds $100,000 for any project whether or not it meets the 15% threshold as shown in Confidential Appendix 2; (3) estimates for the two new projects in Confidential Appendix 3; and (4) a summary of unit cost estimates in Confidential Appendix 4. He stated Petitioner's best estimate of costs rests on a sound factual and analytical foundation and is reasonable.

No party objected to any of the cost estimates and the OUCC recommended the Commission approve Petitioner's Plan Update-1.

Accordingly, we find that Petitioner has provided a sufficient level of detail in support of its Plan Update-1, including justification for the new projects and the cost variances associated with approved projects through its exhibits as well as additional testimony for those projects exceeding the greater of $100,000 or 20%, and we approve these costs in Plan Update-1.

2. **Public Convenience and Necessity.** Petitioner has a statutory obligation to provide reasonably adequate retail service in its certificated gas service territory for the public convenience and necessity pursuant to Indiana Code §§ 8-1-2-4, 8-1-2-87, and 8-1-2-87.5.

Mr. Carr testified that consistent with Petitioner's approved Plan, the eligible improvements included in Plan Update-1 will serve the public convenience and necessity. Mr. Carr testified Petitioner has a statutory obligation to provide adequate retail service in its certificated gas service territory and that Petitioner performs this obligation for the public convenience and necessity. He testified the eligible improvements included in Plan Update-1 are essential in protecting the integrity, safety, and reliable operation of the system and enhance the ability of Petitioner's customers to take advantage of the rapid development of alternative natural gas supply and delivery options and also position Petitioner's system to remain reliable and flexible in the event of significant changes to the economic and operational climate for natural gas. Additionally, he stated that the extension of gas service to rural areas will allow some residents in Petitioner's service territory to access natural gas services for the first time. No evidence was presented in this Cause to contest the continued public convenience and necessity associated with the designated eligible improvements in the Plan.

We find that Petitioner has sufficiently supported that the eligible improvements as described in Plan Update-1 are reasonably necessary for it to continue to provide adequate retail service to its customers, and the public convenience and necessity continues to require or will require those eligible improvements.

3. **Incremental Benefits Attributable to the Updated Plan.** We take into consideration to what extent the Updated Plan will create incremental benefits and whether the costs in the Updated Plan are justified by the incremental benefits attributable to the

Plan. Mr. Carr testified that consistent with the approved Plan, Plan Update-1 focuses on maintaining safe, reliable service for Petitioner's customers in a cost-effective manner. He stated that the emphasis of most of the Plan's investments is to positively impact public safety. Safety drivers focus on risk reduction related to gas system leaks, pipeline ruptures, or incidents of pressure excursion. Reliability drivers include the avoidance of gas outages driven from the inability to maintain gas system pressure during peak load events. Plan Update-1 is also intended to provide benefits in the form of investments to maintain and improve system reliability through the capacity of the system to deliver gas to customers when they need it, the replacement of certain system assets to ensure the ongoing integrity and safe operation of the gas system, and the extension of gas facilities into rural areas.

Mr. Carr stated Rural Extension projects included in Plan Update-1 will continue to increase the number of rural customers served over the life of the Plan. Ms. Becker testified Plan Update-1 cost effectively addresses safety, reliability, system modernization, and the extension of gas service into rural areas, and provides incremental benefits to Petitioner's customers. Mr. Carr testified Petitioner has prioritized and optimized the incremental benefits of Plan Update-1 and shown a sound basis for the proposed projects and associated costs, which is consistent with the standard the Commission has previously applied to the evaluation of incremental benefits under the TDSIC Statute. He testified Plan Update-1 is proposed to reduce the risk of asset failure and maintain service reliability and, in doing so, Plan Update-1 provides incremental benefits compared to how the future would otherwise unfold. No party opposed Commission approval of the costs associated with Plan Update-1.

Based upon the evidence presented in this proceeding and for the reasons set forth above, we find the estimated costs of the eligible improvements included in Plan Update-1 are justified by the incremental benefits attributable to the Plan.

4. Conclusion. Plan Update-1 includes sufficient evidence for us to determine: (1) the best estimate of the cost of the eligible improvements; (2) that public convenience and necessity continues to require or will require the eligible improvements; and (3) the estimated costs of the eligible improvements continue to be justified by the incremental benefits attributable to Plan Update-1. Petitioner's Plan Update-1 appropriately and reasonably addresses Petitioner's aging infrastructure through projects intended to enhance, improve, and replace system assets for the provision of safe and reliable natural gas service, as well as the extension of service into rural areas. Therefore, based on the evidence presented, we approve Plan Update-1. Thus, under Indiana Code § 8-1-39-9(g), we find that the cost variances on the identified projects and new projects are supported by substantial evidence and have been specifically justified. We specifically approve these cost variances and new projects and authorize the recovery of these costs in customer rates.

B. Depreciation and Property Tax Expenses. Petitioner initially proposed to include projected depreciation and property tax expenses instead of recovering the same costs on a historical basis. OUCC witness Mr. Grosskopf recommended removing the projected depreciation and property tax expenses because the projection relied, in part, on utility plant that had not been purchased, completed, or placed in-service as of the cut-off date in this proceeding of June 30, 2020, but rather used forecasted utility plant it assumed would be added in a future period. Mr. Grosskopf explained that IPL and Vectren project these expenses based on actual plant in-service as of the cut-off date. Because they use known plant, the resulting expense projection is accurate. Similarly, Mr. Gorman recommended rejection of Petitioner's proposal because such a projection would be inconsistent with traditional ratemaking, which is based on actually incurred costs and used and useful plant already in-service.

On rebuttal, Petitioner agreed to follow the known plant as of the cut-off date approach proposed by the OUCC and Industrial Group, the same methodology recently approved in IPL and Vectren Orders to calculate depreciation and property tax expenses in TDSIC tracker filings, subject to reconciliation.

The evidence of record demonstrates that Petitioner's method of calculating projected depreciation and property tax expenses on rebuttal is based on the projects completed as of the cut-off date for TDSIC expenditures, making them based on fixed, known, and measurable UPIS, enabling an accurate projection. Consistent with our approval of this same approach for IPL (in Cause No. 45264) and Vectren (in Cause Nos. 44429 and 44910), we find Petitioner's rebuttal proposal, basing depreciation and property tax expenses on projects completed as of the cut-off date for TDSIC expenditures, is reasonable and approved.

C. <u>Pre-tax Return</u>. Indiana Code § 8-1-39-13 establishes how "pre-tax return" is determined for calculating a utility's TDSIC costs. The Commission may consider the following factors:

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

Indiana Code § 8-1-39-13(a).

Under Indiana Code § 8-1-39-13(a)(5), we may consider "other information" that we find necessary in determining a utility's pre-tax return. In Cause No. 45330, both OUCC and Industrial Group recommended that in determining Petitioner's WACC for purposes of its TDSIC cost recovery, we follow the direction recently taken in IPL's TDSIC Plan case (Cause No. 45264), and consider other information regarding specifically the continued collection of a return in base rates on removed assets. In the 45330 Order, we cited our Order in IPL's TDSIC proceeding where we noted that although the TDSIC Statute does not allow for the netting of retired assets, we are not precluded from considering other information and that given the OUCC's continued concerns with double recovery and Industrial Group's concerns with shifting of risks based on TDSIC Plan approval, it was appropriate to explore a reasonable adjustment to the WACC.

Since approval of IPL's TDSIC Plan, we have issued our IPL Order, and it addressed many of the same issues that have been raised here. The IPL Order was issued after Petitioner filed its Petition and case-in-chief, but before the OUCC and Industrial Group filed their testimonies. Although neither the OUCC nor Industrial Group witnesses addressed the findings in the IPL

Order in their testimonies, consistency dictates that we consider it in our determination of these issues here.

i. Depreciation Expense. To address the concern regarding continued recovery of return on retired assets, in its rebuttal, Petitioner calculated its depreciation expense associated with retired and replaced assets and included this amount as a proposed credit to the depreciation expense recovered in this filing related to TDSIC assets. The netting of the depreciation was calculated in a manner similar to the methodology approved for IPL and Vectren. Specifically, Petitioner will use a representative and historical method that relies on a three-year average retirement rate by FERC account using its FERC Form 2 to determine the depreciation reduction adjustment to be applied to its recovery of depreciation expense in its TDSIC tracker proceedings. The resulting adjustment reduces the revenue that would otherwise have been recovered through the TDSIC tracker. Petitioner calculated a $27,219 credit adjustment to the TDSIC utility plant on which the allowed return is based in this Cause.

We continue to acknowledge that Indiana Code § 8-1-39-13(a) allows us to consider "other information" when determining the WACC under Indiana Code § 8-1-39-3(1), such as the impact of retirements. We agree with Petitioner that the netting of depreciation expense reflected in its proposal has the effect of reducing Petitioner's pre-tax return. We recently approved IPL's netting proposal as appropriately addressing the double recovery concern raised by the OUCC and found that based on the reduction to TDSIC cost recovery, no further adjustment to the WACC was required. Indeed, we commended IPL's approach. Similarly, here we find based on the evidence that it is not reasonable to, as proposed by Mr. Gorman, further effectively adjust the assets that were included in rate base in Petitioner's most recent base rate case. The TDSIC Statute addresses TDSIC costs, not rate-based asset costs. *See* Indiana Code § 8-1-39-7. Thus, we find Petitioner's proposed depreciation netting addresses the OUCC and Industrial Group's double recovery concerns and that no further depreciation adjustment is necessary.

ii. Shifting of Risks Based on TDSIC Plan Approval. In its case-in-chief, Mr. Rea updated the COE analysis that he originally prepared as part of Cause No. 44988 to provide the Commission with additional information related to the appropriate pre-tax return applicable to TDSIC investments under the TDSIC Statute. His analysis demonstrated that the calculation of Petitioner's COE results in a point estimate of 10.70%, and, therefore, he testified that his analysis supports an increase to Petitioner's ROE used in the calculation of the pre-tax return in its TDSIC Plan Update filings.

Mr. Rea also testified the recent downward trending interest rate environment must be considered in the context of the currently elevated levels of risk and volatility due to the COVID-19 crisis, consistent with a higher equity risk premium. Mr. Rea opined that there is no question that NIPSCO's revenues, earnings, and operating cash flows have been negatively impacted by the COVID-19 crisis, which increased NIPSCO's investment risk profile.

Mr. Gorman recommended that the Commission reject Petitioner's proposal to implement a 10.70% ROE in measuring the TDSIC incremental revenue requirement and proposed Petitioner's current market COE falls in the range of 9.0% to 9.4%. Mr. Gorman recommended two further adjustments to Petitioner's ROE for TDSIC purposes to address material respects in which TDSIC cost recovery differs from base rate cost recovery. He stated the TDSIC mechanism:

(1) provides opportunity for double recovery associated with asset replacements; and (2) at the same time, largely eliminates the utility risk arising from base rate recovery of capital investments. He recommended that the double recovery and reduced risk each justify a 20-basis point reduction to the ROE for TDSIC revenue, or together a 40-basis point reduction.

Mr. Courter based on the results of the DCF method, CAPM, and macroeconomic analysis, recommended an ROE of 9.0% for purposes of determining the pre-tax return for Petitioner's gas TDSIC tracker.

Mr. Rea in response to Mr. Gorman's proposed 20-basis point reduction to return to address the shift of risks, noted on rebuttal that Petitioner has offsetting elements of risk because of implementing the TDSIC Plan. For example, the large amount of capital expenditures needed to implement its TDSIC Plan would be expected to increase risk, while the purported higher assurance of accelerated cost recovery for the TDSIC investments is often viewed in the context of reducing Petitioner's risk profile.

Mr. Gorman's argument related to a shift of risks in this proceeding is the same as his argument in IPL's Cause No. 45264 TDSIC 1 and is similar to the argument made in Cause No. 44371, wherein the Commission found:

> Some parties recommended that we reduce the return on equity approved in NIPSCO's last general rate case to reflect the reduced risk associated with cost recovery trackers. … Mr. Gorman testified that this tracker will reduce NIPSCO's risk profile significantly, and in his opinion, 9.55% would be an appropriate rate of return on equity. Indiana Code § 8-1-39-13(a) does not preclude us from increasing or decreasing the allowed return on equity, as the Commission is authorized to consider other necessary information in determine the appropriate pre-tax return. However, we note 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 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 ROE from that approved in its most recent rate case.

Northern Indiana Public Service Company, Cause No. 44371, 2014 WL 1373824, at 17 (IURC Feb. 17, 2014), *affirmed in pertinent part by NIPSCO Industrial Group et al. v. NIPSCO*, 31 N.E.3d 1 (Ind. Ct. App. 2015).

The facts and circumstances in Cause Nos. 45264 TDSIC 1 and 44371, in which we rejected the risk reduction argument made by Mr. Gorman on behalf of Industrial Group, are similar here. As reflected in the above excerpt, the Commission gave weight to the time between the last rate case in which Petitioner's ROE was established in rejecting Industrial Group's proposal to reduce Petitioner's ROE. Here, similarly, Petitioner's ROE was established in a September 19, 2018 Order in Cause No. 44988, less than two years before its Petition in this case was filed on August 25, 2020. In addition, Industrial Group was a party to the settlement agreement in Cause No. 44988 in which Petitioner's current ROE was established. At the time of that settlement, Petitioner had been implementing its TDSIC gas plan approved in the Commission's

April 30, 2014 Order in Cause No. 44403. Consistent with our finding on this issue in Cause Nos. 44371 and 45264 TDSIC 1 on the appropriate ROE, we decline to accept Industrial Group's argument in this case to lower Petitioner's authorized ROE from that approved in its most recent rate case (and agreed to by Industrial Group) based on an unsubstantiated reduction in risk with the implementation of the TDSIC Plan.

In our 45330 Order, we found that the parties should provide additional evidence on the impacts of retirements and allocation of risk on Petitioner's pre-tax return, and that such evidence would allow us to consider other information in making our findings as to the applicable WACC in this proceeding. Apart from addressing the two issues we specifically identified, the parties also have submitted additional analysis regarding the appropriate ROE. Petitioner's witness presented evidence that, at a minimum, the return set in its rate case remains reasonable. Similar to our decision in the recent IPL proceeding, we find that the issues we identified related to determination of WACC have been adequately addressed and thus we decline to increase or decrease Petitioner's ROE in this proceeding, As noted above, the approved depreciation expense agreed upon by Petitioner in rebuttal has the effect of adjusting the authorized pre-tax return.

iii. <u>Long-Term Cost of Debt</u>. Mr. Gorman proposed that the Commission should require Petitioner to use its marginal cost of debt, 3.47%, rather than the 4.71% embedded cost of debt for purposes of determining the pre-tax return for Petitioner's gas tracker. Petitioner's Attachment 2, Schedule 1 shows Petitioner's requested overall rate of return used to develop its TDSIC revenue requirement as developed on Attachment 1, Schedule 2. Mr. Gorman said Petitioner's embedded cost of debt is significantly higher than its current market or marginal cost of debt. He stated that due to refinancing and issuance of new debt, Petitioner's embedded cost of debt has been declining significantly. He compared the embedded debt cost of 4.71% as of June 30, 2020, with the embedded debt cost of 5.25% Petitioner used to set its gas base rates as of December 31, 2018.

Mr. Rea testified Mr. Gorman's proposal is inconsistent with the plain language of Indiana Code § 8-1-39-13(a), which states that when determining the pre-tax return for purposes of the TDSIC revenue requirement, the Commission may consider the public utility's capital structure and the "actual cost rates" for the public utility's long-term debt and preferred stock. He pointed out that the statute does not indicate that the incremental or marginal cost of debt should be referenced, and in the instant proceeding, Petitioner has calculated its cost of long-term debt using actual cost rates, which is in accordance with the plain language of the statute.

In Cause No. 44371, in which Mr. Gorman offered similar recommendations regarding the calculation of pre-tax return, we found:

> [W]e are not persuaded that a capital structure more in line with project specific financing is appropriate. The regulatory capital structure for NIPSCO as an enterprise includes equity, debt and zero cost capital. We believe NIPSCO and other Indiana utilities are better viewed as an ongoing concern that utilizes all of their capital resources in a holistic manner to finance that ongoing concern, including resources which have no cost attached. This view and methodology is consistent with other long-standing capital investment trackers such as the ECRs. Accordingly, the Commission finds that NIPSCO shall calculate WACC in a

manner consistent with its last rate case and ECR proceedings, which includes zero cost capital in the capital structure.

Northern Indiana Public Service Company, 2014 WL 1373824, at 17.

Furthermore, Mr. Gorman's precise argument here was rejected in the IPL Order. The evidence in this proceeding does not lead to a different conclusion. Such an approach is also supported by the language of Indiana Code § 8-1- 39-13(a)(2), which refers to "the public utility's capital structure," and Indiana Code § 8-1-39-13(a)(3), which refers to "actual cost rates for the public utility's long-term debt and preferred stock." Thus, for these reasons, we approve Petitioner's use of its actual capital structure as of the June 30, 2020 cut-off date, and the actual cost rate for the long-term debt component of its capital structure in calculating its TDSIC revenue requirement.

iv. Conclusion. We find that Petitioner's proposed depreciation netting addresses the OUCC's and Industrial Group's double recovery concerns and no further depreciation adjustment is necessary. We commend Petitioner's netting proposal, which has the positive effect of reducing the authorized return that it would have received if the adjustment were not made, thus addressing the concerns about this topic that were raised by the other parties. We decline to decrease the authorized ROE, as proposed by the Industrial Group. Similar to our decision in the recent IPL proceeding, we find that the issues we identified related to determination of WACC have been adequately addressed in this Cause, and we decline to increase Petitioner's authorized ROE, as proposed by Petitioner, as it was relatively recently approved in our 44988 Order (and agreed to by the OUCC and Industrial Group). Regarding the appropriate long-term debt to be utilized in determining the revenue requirement, we find that Petitioner's proposed use of its embedded cost of long-term debt of 4.71% should be utilized in accordance with plain language of Indiana Code § 8-1-39-13(a).

D. Indiana Code § 8-1-39-11(c). This statute requires in part that a gas public utility may, on a nondiscriminatory 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 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 20-year period, the public utility may require a deposit or other adequate assurance of performance.

Petitioner requested Commission approval to, on a nondiscriminatory 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 20-year period. Mr. Carr testified the Rural Extension projects included in Plan Update-1 are projected to pass the 20-year test identified in Indiana Code § 8-1-39-11. Petitioner's Rural Extension request is consistent with the applicable statute and is approved.

E. Indiana Code § 8-1-39-13(b). This statute requires that the Commission shall adjust a public utility's authorized return for purposes of Indiana Code §§ 8-1-2-42(d)(3) or 42(g)(3) to reflect incremental earnings from an approved TDSIC. Petitioner requested Commission approval to adjust its authorized return for purposes of Indiana Code § 8-1-2-42(g)(3) to reflect the incremental earnings that will result from the TDSIC filing. This request is consistent with the applicable statute and is approved.

F. **Indiana Code § 8-1-39-14.** In relevant part, this statute provides that the Commission may not approve a TDSIC that would result in an average aggregate increase in a public utility's total retail revenues of more than 2% in a 12-month period. Ms. Dousias testified that the aggregate increase in Petitioner's total retail revenues resulting from this TDSIC tracker is less than the 2% statutory TDSIC limit. Thus, we find that Petitioner's proposed TDSIC 1 factors will not result in an average aggregate increase in total retail revenues of more than 2% in a 12-month period and complies with Indiana Code § 8-1-39-14.

G. **TDSIC 1 Factors.** For the reasons explained above, Petitioner's proposed TDSIC 1 factors and associated revisions to its tariff, as set forth in Petitioner's Exhibit 1, Attachment 1-A, Attachment 1, Revised Schedule 8, are approved. An average residential customer using 69 therms per month will experience an increase of $0.85 on their monthly bill.

TDSIC 1 Rider Factors	
Rate Schedule	**TDSIC Charge per Therm per Month**
Rate 111 (with associated Rate 151, Riders 180 and 181)	$0.004613
Rate 115 (with associated Rate 151, Riders 180 and 181)	$0.009504
Rate 121 (with associated Rate 151, Riders 180 and 181)	$0.003463
Rate 125 (with associated Rate 151, Riders 180 and 181)	$0.002073
Rate 128	$0.000132
Rate 138	$0.000624

6. **Confidentiality.** On August 25, 2020, Petitioner filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information, which was supported by affidavit from Ryan J. Carr, E&C Manager of NIPSCO, showing documents to be to the Commission were trade secret information within the scope of Indiana Code §§ 5-14-3-4(a)(4) and (9) and Indiana Code § 24-2-3-2. The Presiding Officers issued a Docket Entry on September 11, 2020, finding such information to be preliminarily confidential, after which such information was submitted under seal. We find all such information is confidential pursuant to Indiana Code § 5-14-3-4 and Indiana Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

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

1. Petitioner Northern Indiana Public Service Company TDSIC Plan Update-1 is approved.

2. Petitioner is authorized to defer, as a regulatory asset, and recover 80% of the approved capital expenditures and TDSIC costs incurred in connection with its eligible improvements approved in its rates and charges for gas service in accordance with Petitioner's TDSIC beginning January 2021.

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

4. Petitioner is authorized to defer, as a regulatory asset, 20% of the TDSIC costs incurred in connection with its eligible improvements and recover those deferred costs in its next general rate case.

5. Petitioner is authorized to record ongoing carrying charges based on the current overall WACC on all deferred capital expenditures and TDSIC costs until such costs are recovered in Petitioner's base rates in its next general rate case.

6. The TDSIC Factors set forth in Petitioner's Exhibit 1, Attachment 1-A, Attachment 1, Revised Schedule 8 are approved to be effective for bills rendered by Petitioner for January through June 2021, or until replaced by different factors approved in a subsequent filing.

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

8. The information filed by Petitioner in this Cause pursuant to its Motion for Protective Order is deemed confidential pursuant to Indiana Code § 5-14-3-4 and Indiana 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.

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

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

APPROVED: DEC 23 2020

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

Regina K. Joyner Digitally signed by Regina K. Joyner Date: 2020.12.23 10:14:47 -05'00'

Mary M. Schneider
Secretary of the Commission