STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

FILED
October 27, 2020
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**

Verified Direct Testimony and Attachments of

Michael P. Gorman

On behalf of

The NIPSCO Industrial Group

October 27, 2020

BRUBAKER & ASSOCIATES, INC.

Project 11043

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<u>Direct Testimony of Michael P. Gorman</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A The NIPSCO Industrial Group ("Industrial Group"). Industrial Group members purchase substantial quantities of natural gas services from Northern Indiana Public Service Company ("NIPSCO" or "Company").

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A I will comment on NIPSCO's proposed measurement of the revenue requirement in support of its Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") that supports the TDSIC investment plan. NIPSCO is proposing to implement a surcharge for qualifying TDSIC transmission, distribution and storage plant investments that will supplement is revenue collections from customers based on current base rate charges to support these incremental plant investments. My testimony outlines adjustments to the Company's proposed measurement of the revenue requirement recovered through the TDSIC to more accurately reflect incremental revenue requirements associated with these new plant investments, and thus ensure that customers' combined charges of base rates and TDSIC charges represent fair and reasonable charges to customers.

Specifically, in implementing the TDSIC revenue requirement I recommend the following modifications to the Company's proposal:

1. I recommend that the Commission reject NIPSCO's proposal to implement a substantial increase to its base rate return on equity in measuring the TDSIC incremental revenue requirement because that proposal does not accurately and reasonably reflect a current estimate of NIPSCO's capital market costs. Based on my assessment of the Company's updated market

return on equity study, I believe NIPSCO's current market cost of equity falls in the range of 9.0% to 9.4%.

2. I recommend two further adjustments to NIPSCO's return on equity for TDSIC purposes to address material respects in which TDSIC cost recovery differs from base rate cost recovery. Specifically, the TDSIC mechanism provides opportunity for double recovery associated with asset replacements, and at the same time largely eliminates the utility risk arising from base rate recovery of capital investments. The double recovery and reduced risk each justify a 20 basis point reduction to the return on equity for TDSIC revenue, or together a 40 basis point reduction.

3. As an alternative to a reduction in return on equity for TDSIC purposes to account for the double recovery issue, I recommend a more direct method to adjust the revenue requirement to reflect net depreciation. First, the depreciation expense should reflect the increased depreciation expense with new TDSIC investments, but should be offset by embedded TDSIC plant investments that are retired and taken out of service. The net change in NIPSCO's depreciation expense will reflect this depreciation expense for new plant investment, less the depreciation expense recorded in base rates for plant that will be retired. Second, I recommend a roll-forward of depreciation expense in measuring the change in net plant in-service for the TDSIC transmission, distribution and storage facilities. Measuring the TDSIC revenue requirement based on a measurement of incremental growth in rate base due to these plant investments will ensure customers' total rate charges including base rates and TDSIC charges will be just and reasonable

4. .I recommend the rate of return for TDSIC revenue requirements be based on marginal cost of debt. Evidence shows that NIPSCO's embedded cost of debt has been decreasing significantly over time. Base rates currently are designed to recover embedded interest costs that are significantly in excess of NIPSCO's current interest costs. TDSIC incremental revenue requirements should reflect the incremental debt cost, not the embedded debt cost. For these reasons, I recommend the TDSIC represent the average embedded debt cost for debt issued after January 1, 2021 and designed in the TDSIC revenue requirement.

5. I recommend that NIPSCO's proposal to recover depreciation and property tax expenses on a projected basis should be rejected. NIPSCO'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.

First, I will be addressing the Company's proposal to increase the authorized return on equity recovered through the TDSIC to 10.70% from the 9.85%[1] awarded in its 2017 gas rate case. I will comment on the appropriateness of recalibrating the return on equity for the TDSIC incremental plant investments to reflect NIPSCO's capital market costs during the period these new capital investments will be made and incremental costs will be charged to customers. I believe the increase proposed by NIPSCO is unreasonable, unsupported, and inconsistent with current market conditions. If the Commission finds it appropriate to update NIPSCO's return on equity for TDSIC purposes in order to align with changed conditions subsequent to its last rate case, it is more appropriate to make a downward adjustment reflecting the lower cost capital cost market environment during the term of this TDSIC Plan.

Second, I recommend two adjustments to NIPSCO's authorized return for purposes of computing TDSIC revenue requirements. The first adjustment recognizes the double recovery associated with replaced assets under the TDSIC mechanism, by which NIPSCO is able to recover return associated with removed assets as embedded in base rates while concurrently recovering redundant costs for replacement assets under the TDSIC mechanism. Importantly, NIPSCO is not proposing to implement any kind of netting process to offset that double recovery. Absent netting, the authorized return for TDSIC purposes should be less than the return allowed for base rates, in order to mitigate the excessive charges on customers. The other proposed adjustment reflects the distinct risk profile for preapproved TDSIC investments, in contrast to the risks reflected in base rates. The TDSIC mechanism eliminates nearly all of the risks associated with recovery through base rates, and shifts substantial risk to NIPSCO's customers. Since authorized return is properly calibrated to the level of utility risk, the

[1]Cause No. 44988, Final Order at 100.

elimination of risk specific to TDSIC investments should be correlated to a reduced return for purposes of calculating TDSIC revenue requirements.

Third, in the event the Commission elects to address the double recovery issue more directly instead of through an adjustment to TDSIC return, I recommend a depreciation netting methodology that would fully remedy the double recovery. This netting methodology can be accomplished in two ways. First, NIPSCO should net increases in depreciation expense based on new TDSIC plant investments, offset by depreciation expense currently recovered in base rates, but for a plant that will be retired by the new TDSIC plant investments. This net depreciation expense will allow NIPSCO to recover its incremental depreciation expense caused by its TDSIC plant additions less related plant retirements (due to TDSIC plant replacing older plant) during the period the TDSIC charges are in effect.

The second depreciation netting adjustment relates to the measurement of the incremental rate base due to TDSIC investments. NIPSCO's incremental increase in its rate base caused by its TDSIC investments should track the change in net plant for all investments recorded in the same FERC account as the TDSIC investments will be recorded. If the TDSIC rate base tracks changes in gross plant investment, offset by a roll-forward of accumulated deferred taxes for all investments recorded in these FERC accounts, then the TDSIC charge can be based on incremental revenue requirement related to incremental plant growth. Again, this will protect NIPSCO's customers from paying excessive combination charges from base rates and TDSIC charges, while providing NIPSCO full recovery of its TDSIC and other plant investment recorded in the TDSIC FERC accounts. Given the lack of any netting proposal at all by NIPSCO, the excessive recovery arising from asset replacements should be fully addressed by the netting methodology that I describe, or by an adjustment to authorized return for TDSIC purposes that provides a commensurate reduction in charges to customers.

Fourth, I recommend the TDSIC be based on the marginal cost of debt instead of embedded cost of debt. NIPSCO's embedded cost of debt is already built into and recovered in NIPSCO's base rates. Incremental TDSIC investments will be financed with marginal cost of debt, not embedded debt cost. Because NIPSCO's marginal cost of debt is significantly lower than its embedded debt cost, using this methodology more accurately reflects NIPSCO's incremental revenue requirement related to incremental TDSIC plant investments that will be recovered through the TDSIC charge. A combination of embedded debt costs being recovered in base rates, and the incremental costs being recovered in TDSIC charges will ensure that customers' combined bills, both base rates and TDSIC charges, will reasonably reflect NIPSCO's actual debt costs.

Fifth and finally, I recommend that the Commission deny NIPSCO's proposal to recover depreciation and property taxes on a projected basis, subject to reconciliation. That proposal is contrary to the approach that NIPSCO has followed in its TDSIC filings for more than six years, and is unsupported by any change of circumstance or valid reason requiring a revision. Under traditional ratemaking, the utility must first actually incur a cost before implementing a rate adjustment to recover it. NIPSCO has not identified any statutory provision altering that principle for purposes of TDSIC costs. As a matter of policy, rate adjustments should be based on actual costs that the utility is able to report it has incurred, not based on projections and expectations.

Q PLEASE DESCRIBE NIPSCO'S PROPOSAL TO IMPLEMENT A TDSIC.

A NIPSCO is requesting to implement TDSIC charges based on its TDSIC capital plan, which reflects incremental plant investments for transmission, distribution, and storage facilities. NIPSCO's plan calls for the development of revenue requirements based on the return on and of these TDSIC plant investments, incremental depreciation expense related to these new plant investments, and related property tax expenses. These TDSIC revenue requirements then will be used to develop TDSIC charges based on the Company's proposed spread of these investments over its various rate classes.

I. RETURN ON EQUITY

I.A. NIPSCO'S Proposal

Q PLEASE DESCRIBE THE AUTHORIZED RETURN ON EQUITY THAT NIPSCO IS PROPOSING TO USE IN ITS NEW TDSIC INVESTMENT.

A NIPSCO witness Vincent V. Rea is requesting that the return on equity be set at 10.70%. He measures this as an updated cost of equity estimate for NIPSCO's investment risk, and states that this return on equity falls within his estimated cost of equity range for NIPSCO of 10.45% to 10.95%.[2]

Mr. Rea believes that NIPSCO's cost of equity has increased since its last case, which is attributable to the recent economic distress caused by the COVID-19 pandemic.

Mr. Rea testifies that the economic turmoil more recently has caused more volatility in the stock market, which has increased NIPSCO's investment risk. According to Mr. Rea, the Federal Reserve actions have distorted capital market costs,

[2]Direct Testimony of Vincent V. Rea at 9.

which are not giving a clear indication of the market's required return for investments with risks similar to that of NIPSCO.

Mr. Rea further testifies that independent economists' assessments of changes in capital market costs are fully aware of the Federal Reserve's monetary actions and are expecting increases in capital market costs.

Q IS IT APPROPRIATE FOR THE COMMISSION TO AUTHORIZE A DISTINCT RETURN FOR PURPOSES OF TDSIC RECOVERY THAT IS DIFFERENT FROM THE BASE RATE RETURN ALLOWED IN THE MOST RECENT RATE CASE?

A Based on pages 27-28 of the Commission's Final Order in Cause No. 45330, approving NIPSCO's Gas TDSIC Plan, the Commission may consider "other information" that it deems relevant to determining an appropriate return for TDSIC purposes, and in doing so is not required to utilize the same return authorized for base rates in the utility's most recent rate case. My understanding, therefore, is that the Commission has discretion to decide what "other information" is deemed relevant to that determination.

Q DO YOU BELIEVE THE INCREASED RETURN PROPOSED BY MR. REA IN THIS CASE IS REASONABLE?

A No. The elevated 10.7% return proposed by Mr. Rea is excessive, unsupported, and inconsistent with current capital market conditions. In the event that the Commission deems it appropriate to consider changed circumstances subsequent to NIPSCO's last rate case as "other information" relevant to determining an appropriate TDSIC return, I will explain that a return below what was allowed in the last rate case should be applied to TDSIC recovery in light of prevailing trends and current market conditions.

I.B. Market Cost of Equity

Q DOES MR. REA PRESENT AN ANALYSIS THAT SUPPORTS HIS FINDINGS ON A FAIR RETURN ON EQUITY FOR NIPSCO IN THIS PROCEEDING?

A Yes. Mr. Rea develops a Discounted Cash Flow ("DCF"), a Traditional Capital Asset Pricing Model ("CAPM"), an Empirical CAPM ("ECAPM") analyses, and a Risk Premium analysis on three proxy groups: a Gas LDC Group, a Combination Utility Group, and a Non-Regulated Group.

As outlined in his Table 3 and as discussed on page 9 of his testimony, these analyses support Mr. Rea's finding that NIPSCO's current market cost of equity falls in the range of 10.45% to 10.95%, with a midpoint of 10.70%, which he proposes the Commission adopt in this regulatory proceeding. For the reasons explained below and in Appendix B to my testimony, I disagree with Mr. Rea's analysis in a number of important respects.

Q HOW DO MR. REA'S MARKET COST OF EQUITY STUDIES AND RECOMMENDED RETURN COMPARE TO NIPSCO'S MOST RECENT NATURAL GAS CASE AND ELECTRIC CASE?

A Mr. Rea's findings on NIPSCO's current market cost of equity are comparable to the results of his studies in NIPSCO's 2018 electric case and 2017 gas case. I summarize Mr. Rea's findings that he offers in his verified direct testimony from each of these cases, and in this case, in my Table 1 below.

TABLE 1

Rea Recommended DCF and CAPM Results

Description	Last Electric (1)	Last Gas (2)	This Case (3)
IURC Authorized ROE	9.75%	9.85%	
DCF	10.55% - 11.05%	10.25%	10.71% - 10.91%
CAPM	10.45% - 10.95%	10.50%	10.56% - 10.61%
RP	10.65% - 11.15%	10.70%	10.22%

Sources:
Cause No. 45159, Rea Direct Testimony at Page 10, Table 3.
Cause No. 44988, Rea Direct Testimony at Page 10, Table 3.
Rea Direct Testimony at 9, Table 3.

As shown above in Table 1, in the current case, Mr. Rea's DCF return estimates are slightly higher than he found in the 2017 gas case, but reasonably in line with his findings in NIPSCO's 2018 electric case.

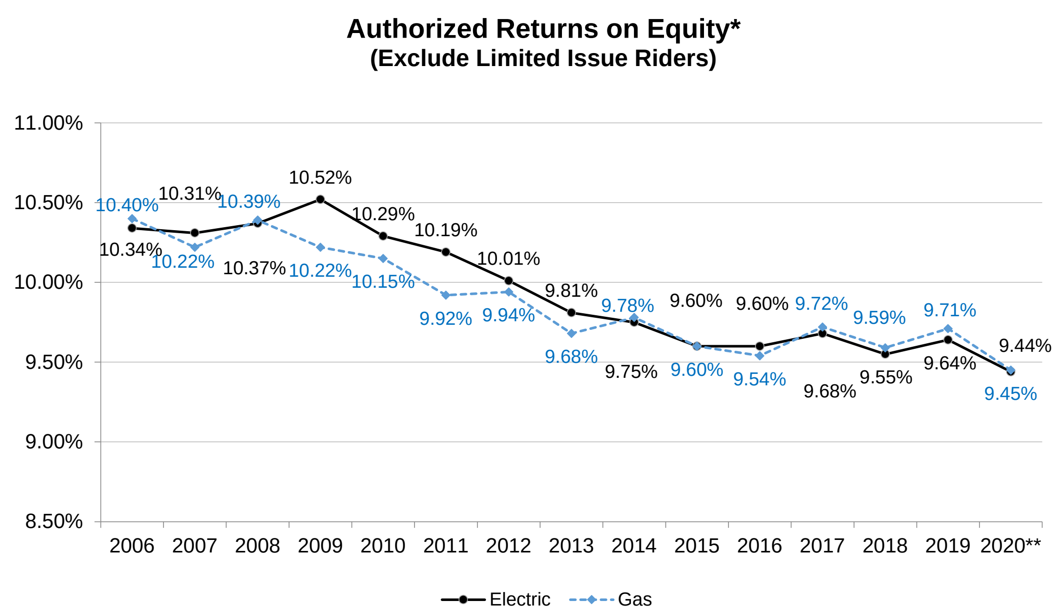
In the 2017 gas case and 2018 electric case, Mr. Rea recommended the Commission award NIPSCO a return on equity of 10.70% and 10.80%, respectively. However, in those rate cases, the Commission approved settlements in which NIPSCO agreed to much lower figures, and on that basis the Commission awarded NIPSCO a return on equity of 9.85% in the gas case and 9.75% in the electric case.

In this case, again Mr. Rea has recommended a return on equity that aligns with his proposed return in NIPSCO's last gas rate case, and comparable to what he recommended in the electric case. The Commission should again set Mr. Rea's return on equity recommendation aside, and award NIPSCO a fair market-based return for the TDSIC Rider.

Q HAS THERE BEEN A NATIONAL TREND IN AUTHORIZED RETURNS ON EQUITY FOR REGULATED UTILITY COMPANIES, BOTH ELECTRIC AND GAS, SINCE NIPSCO'S 2017 GAS CASE AND 2018 ELECTRIC CASE?

A Yes. There has been a declining trend in authorized returns on equity for both electric and gas companies. This is outlined in the figure below.

FIGURE 1



Source and Notes:
[1] *S&P Global Market Intelligenc* e, RRA Regulatory Focus, Major Rate Case Decisions -- January - September 2020, October 20, 2020 at page 1.
* Electric Returns exclude Limited Issue Riders.
* RRA excludes the 2017 Alaska ENSTAR decision from its calculations.
**Data represents January - September.

As shown in the figure above, the authorized return on equity for electric and gas utilities in 2017 and 2018 is approximately 9.68%/9.72% and 9.55%/9.57%, respectively. Through the first nine months in 2020, the authorized returns on equity for both electric and gas utilities have dropped below 9.5%, specifically, 9.44% and 9.45% for electric and gas utilities, respectively.

I would note that with this decline in authorized returns on equity, electric and gas utilities' credit outlooks are largely noted as "Stable" by credit rating agencies, and these utilities have access to significant amounts of capital to support very large investments in rate base infrastructure. For these reasons, observable market evidence shows that customers are benefitting from declining capital market costs, and utilities are still able to fund significant rate base investments while adjusting rates to reflect today's very low capital market costs.

Q WHY DO YOU BELIEVE THAT UTILITIES HAVE BEEN ABLE TO ACCESS EXTERNAL CAPITAL TO SUPPORT CAPITAL EXPENDITURE PROGRAMS?

A In its June 2020 Utility Capital Expenditures Update report, *RRA Financial Focus*, a division of S&P Global Market Intelligence, made several relevant comments about utility investments generally:

> - Projected 2020 capital expenditures for the 48 energy utilities in the Regulatory Research Associates', [sic] a group with S&P Global Market Intelligence, universe currently stands at roughly $140.9 billion, well above 2019's $121.3 billion in capital investment.
>
> - 2019's energy capital expenditures were a record high, and 5% above the $115.1 billion posted in 2018.
>
> * * *
>
> The nation's electric and gas utilities are investing in infrastructure to upgrade aging transmission and distribution systems, build new natural gas, solar and wind generation, and implement new technologies, including smart meter deployment, smart grid systems, cybersecurity measures and battery storage. We expect considerable levels of spending to serve as the basis for solid profit expansion for the foreseeable future.[3]

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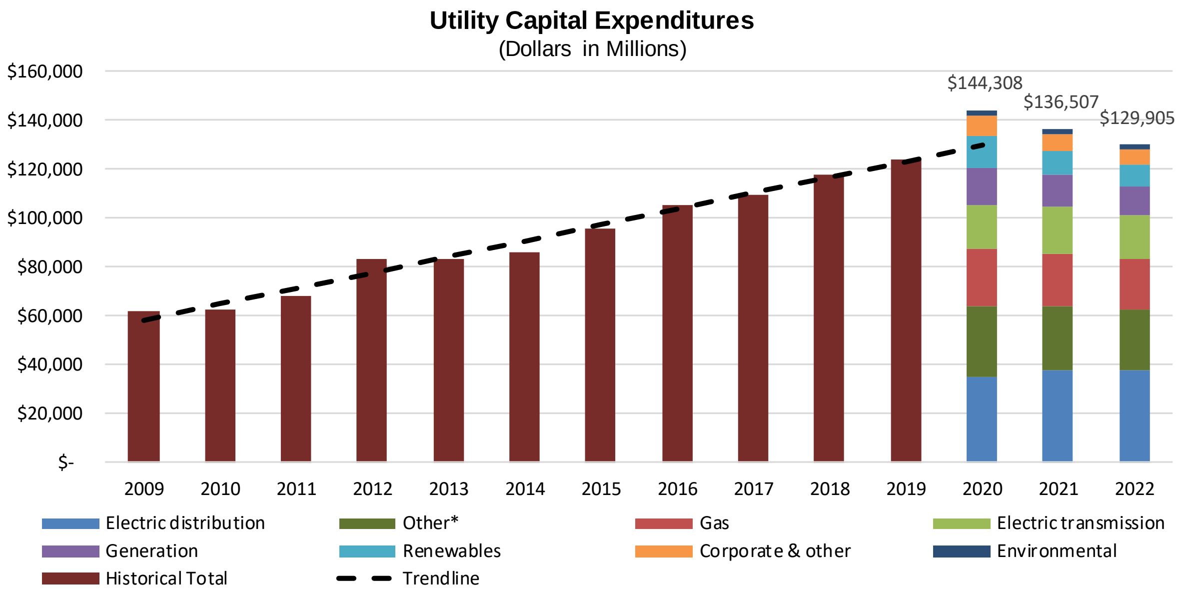
[3] *S&P Global Market Intelligence, RRA Financial Focus*: "Utility Capital Expenditures Update," June 8, 2020, at 1.

As shown in Figure 2 below, capital expenditures for electric and natural gas utilities have increased considerably over the period 2009 into 2020, and the forecasted capital expenditures remain elevated, but slightly below current levels.

FIGURE 2



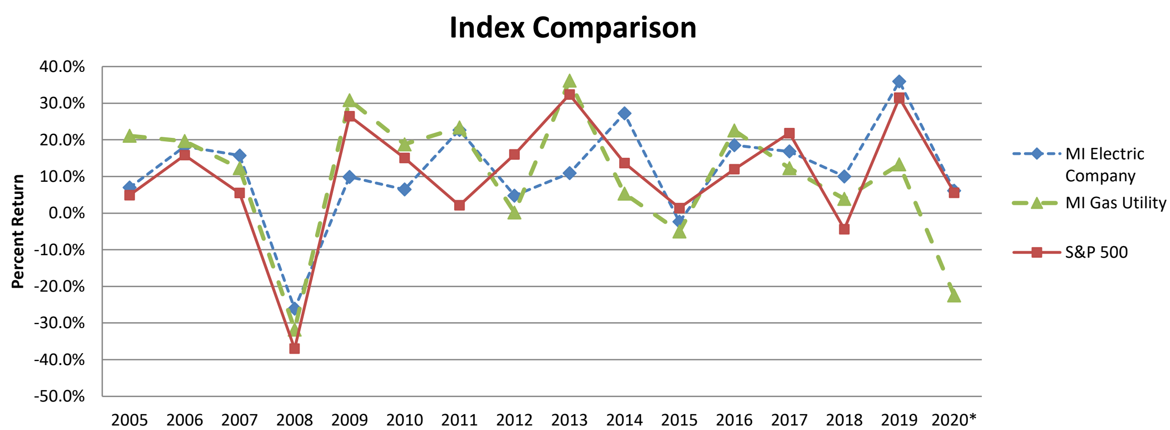
*Other category consists of utilities that do not report capital expenditures by category: Avangrid, Hawaiian Electric, PG&E and Portland General Electric.
Source: *S&P Global Market Intelligence, RRA Financial Focus*, Utility Capital Expenditures Update, June 8, 2020, Tables 1 and 3.

As outlined in Figure 2 above, and in the comments made by *RRA S&P Global Market Intelligence*, capital investments for the utility industry continue to stay at elevated levels, and fuel utilities' profit expansion into the foreseeable future. This is clear evidence that the capital investments are enhancing shareholder value, and are attracting both equity and debt capital to the utility industry in a manner that allows for these accelerated capital investment levels. While these profit-driven capital investments are embraced by the capital markets, regulatory commissions must also keep a careful view toward maintaining reasonable prices, and terms and conditions to protect customers' need for reliable service at competitive prices.

Q PLEASE DESCRIBE UTILITY STOCK PRICE PERFORMANCE OVER THE LAST SEVERAL YEARS.

A As shown in Figure 3 below, S&P Global Market Intelligence ("MI") has recorded utility stock price performance compared to the market. The industry's stock performance data from 2005 through 2020 shows that the MI Electric Company and MI Gas Utility Indexes have followed the market through downturns and recoveries. However, utility investments have been less volatile during extreme market downturns. This more stable price performance for utilities supports my conclusion that market participants regard utility stock sectors as a moderate- to low-risk investment option.

FIGURE 3



Source: S&P Global Market Intelligence.
***Data through September 2020**

While utility stocks have not exhibited the same volatility as the S&P 500, stock prices have remained strong, relative to the market in general, and support the utilities' access to equity capital markets under reasonable terms and prices.

I.C. Summary of Mr. Rea's Updated Return on Equity Results

Q WHAT IS NIPSCO'S RETURN ON EQUITY RECOMMENDATION?

A As outlined above, Mr. Rea recommends a return on equity of 10.70%, which is the midpoint of his recommended range of 10.45% to 10.95%. Mr. Rea's recommended range and return on equity were developed based on the results of his DCF method, traditional CAPM method, empirical CAPM ("ECAPM") method, and Risk Premium Method ("RPM) that were applied to a gas LDC proxy group, a combination utility proxy group and a non-regulated proxy group.[4] As discussed in Appendix B to my testimony I find the use of a non-regulated proxy group unreasonable and my analysis of Mr. Rea's results is focused on his utility proxy groups. In the development of his return estimates, Mr. Rea included an adjustment of 5 basis points for flotation costs, a market-to-book adjustment of 121 basis points and a size adjustment in the range of 0.70 to 1.10 for his utility proxy groups.

In developing his range, Mr. Rea states that his recommendation is most heavily influenced by the results of his DCF because the CAPM and RPM methods have recently been subject to a greater volatility due to rapidly changing long-term interest rates and beta coefficients.[5] The results of Mr. Rea's analyses are summarized in the first column of Table 2 below.

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[4] Rea Direct Testimony at 9-10.
[5] *Id*. at 10.

TABLE 2

Mr. Rea's ROE Analysis

Model	**Average (1)**	**Corrected (2)**
DCF		
Analyst Growth	8.30% - 10.10%	8.90% - 9.20%
Retention Growth	7.3%	Reject
Hist. EPS Growth	9.50% - 10.20%	Reject
Unadjusted DCF Return	9.15% - 9.45%	8.90% - 9.20%
CAPM		
Unadjusted	10.42% - 10.51%	9.10% - 9.20%
Size Adjusted	11.52% - 11.24%	Reject
ECAPM	10.73% - 10.80%	Reject
Risk Premium		
Projected	10.06% - 10.17%	9.00% - 9.40%
Non-Utility Range	9.3% - 13.40%	Reject
Flotation Cost Adjustment	0.05%	Reject
Market-to-Book Adjustment	1.21%	Reject
Adjusted Range	**10.45% - 10.90%**	**8.9% - 9.4%**
Recommended ROE	**10.70%**	**9.4%**

Source: Rea Direct Testimony at 28-29, 32, 34.

As outlined in the table above, a balanced and careful review of the results of Mr. Rea's studies shows that his DCF study, reflecting only prospective consensus analysts' growth rate estimates, would support a return on equity for NIPSCO in the current market of around 8.9% to 9.2%. Using his CAPM study, reflecting only DCF returns on the S&P 500 to produce the market risk premium, and using two-year projected Treasury bond yields as more reflective of the current marketplace, would produce a CAPM return estimate in the range of 9.1% to 9.2%. Further, adjusting his risk premium analysis to reflect current observable bond yields, instead of his projected bond yields produces more reliable risk premium estimates. Reflecting observable bond yields and a historical gauge to equity risk premiums would support a risk premium in the area of 9.0% to 9.4%. A more detailed review and evaluation of Mr. Rea's return on equity results are outlined in my Appendix B.

I.D. Federal Reserve's Impact on Cost of Capital

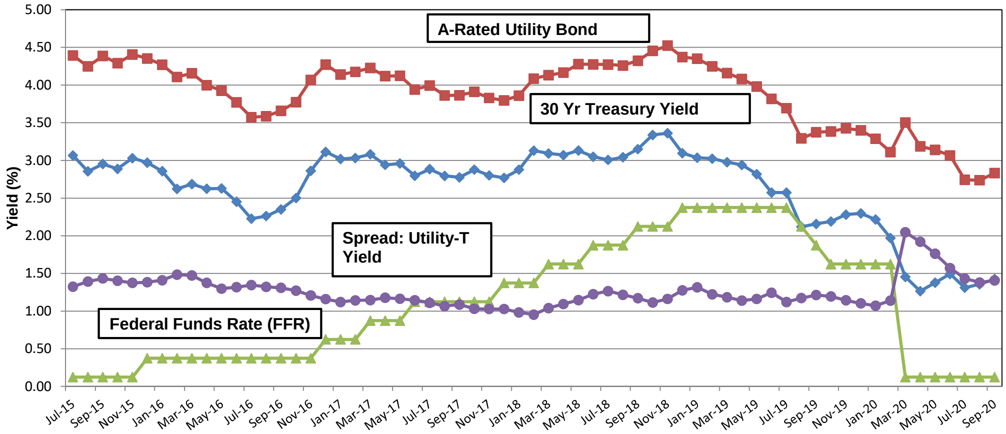
Q AT PAGES 13-15 OF MR. REA'S TESTIMONY, HE OUTLINES THE FEDERAL RESERVE'S ACTIONS AND THE POTENTIAL IMPACT ON CAPITAL MARKET COSTS. DO YOU BELIEVE THAT THE FEDERAL RESERVE'S ACTIONS ARE FULLY KNOWN BY MARKET PARTICIPANTS AND FULLY REFLECTED IN THE VALUATION OF MARKET SECURITIES, BOTH DEBT AND EQUITY?

A Yes, I do. While the Federal Reserve's previous actions on Quantitative Easing and more recent reentry into both the Treasury, mortgage-backed security, and now to limited extent corporate bond market, the Federal Reserve's actions were done in order to preserve stability and liquidity in the market and to calm the marketplace. These Federal Reserve actions are not intended to drive down interest rates or manipulate the market in any way. The effects of these measures, and the outlooks by independent economists, continue to support the notion that capital market costs will stay low for the extended period of time. Indeed, this is illustrated through a comparison of independent economists' projections, effects on short-term market costs and long-term security costs.

An assessment of the market's reaction to the Federal Reserve's impact on the Federal Funds Rate or short-term markets is shown below in Figure 4.

FIGURE 4

Timeline of Federal Funds Rate Changes Since 2015



Fed FFR Actions:		Midpoint of FFR	Change			Midpoint of FFR	Change
1	December 2015	0.375		8	September 2018	2.125	0.25
2	December 2016	0.625	0.25	9	December 2018	2.375	0.25
3	March 2017	0.875	0.25	10	August 2019	2.125	(0.25)
4	June 2017	1.125	0.25	11	September 2019	1.875	(0.25)
5	December 2017	1.375	0.25	12	October 2019	1.625	(0.25)
6	March 2018	1.625	0.25	13	March 2020	1.125	(0.50)
7	June 2018	1.875	0.25	14	March 2020	0.125	(1.00)

Sources:
Federal Reserve Bank of New York, https://apps.newyorkfed.org/markets/autorates/fed-funds-search-page
Board of Governors of the Federal Reserve System, https://www.federalreserve.gov/datadownload/
Moody's Credit Trends, https://credittrends.moodys.com/

As shown in Figure 4 above, while the Federal Reserve has reduced short-term interest rates currently, as they did back in the period prior to 2015, the market's valuation of long-term securities remains relatively stable, and at very low costs. The Federal Reserve's interaction in short-term securities is specifically stated to manage inflation and support employment in the economy. The Federal Reserve's interaction in these marketplaces is not to manipulate utility valuation or security valuations, or drive capital market costs in one direction or the other. Rather, it is strictly for the purpose of supporting the U.S. economy.

Further, the outlook for long-term interest rates in an intermediate to longer term is also impacted by the current Federal Reserve actions and the expectation that eventually that the Federal Reserve's monetary actions will return to more normal levels. Its impacts in long-term interest rate projections are illustrated in Table 3 below.

TABLE 3

30-Year Treasury Bond Yield Actual Vs. Projection

Description	Quarterly Average	2-Year Projected	5- to 10-Year Projected
2015			
Q1	2.97%	4.00%	4.9% - 5.1%
Q2	2.55%	3.70%	
Q3	2.83%	4.00%	4.8% - 5.0%
Q4	2.84%	3.90%	
2016			
Q1	2.96%	3.80%	4.5% - 4.8%
Q2	2.72%	3.60%	
Q3	2.64%	3.40%	4.3% - 4.6%
Q4	2.29%	3.10%	
2017			
Q1	2.82%	3.70%	4.2% - 4.5%
Q2	3.05%	3.80%	
Q3	2.91%	3.70%	4.3% - 4.5%
Q4	2.82%	3.60%	
2018			
Q1	2.82%	3.60%	4.1% - 4.3%
Q2	3.02%	3.80%	
Q3	3.09%	3.80%	4.2% - 4.4%
Q4	3.07%	3.70%	
2019			
Q1	3.27%	3.40%	3.9% - 4.2%
Q2	3.01%	3.10%	
Q3	2.78%	2.60%	3.6% - 3.8%
Q4	2.30%	2.50%	
2020			
Q1	2.30%	2.60%	3.2% - 3.7%
Q2	1.89%	1.90%	3.0% - 3.8%

Sources:
Blue Chip Financial Forecasts ,
December 2013 through June 2020.

As shown in Table 3 above, independent economists' projections of changes in long-term Treasury rates are very different today than it was over the last five to six years. Specifically, in 2015 economists were expecting that Treasury bond yields, which fell below 3%, would eventually return to the high 4s or 5 percentage point area. That outlook largely remained through 2016, but the outlook for future capital market costs started to decline in 2017. More recently, Treasury bond yields have dropped to historically low levels but are expected to stay low for the next five to ten years.

Again, the market is fully aware of the Federal Reserve actions, and these actions are not expected to have significant changes in capital market costs over the next five to ten years. Further, these Federal Reserve actions are expected to maintain relatively stable capital market costs over the next two years.

I.E. Market Volatility – Chicago Board of Exchange ("CBOE"), VIX

Q DID MR. REA ALSO OPINE THAT MARKET VOLATILITY HAS INCREASED, WHICH HAS CAUSED AN INCREASE IN COST OF EQUITY FOR NIPSCO AND OTHER UTILITY COMPANIES?

A Yes. Mr. Rea also talks about increased volatility as measured by the CBOE Implied Volatility Index ("VIX"). Mr. Rea states that the VIX index indicates greater volatility in the index which generally tracks broader market equity security values. He states that this index implies greater volatility in 2020 than it did in 2017 and 2018, the time period that reflects NIPSCO's previous rate cases.

Q IS THE VIX INDEX ADEQUATE TO SUPPORT THE NOTION THAT THE MARKET PERCEPTION OF THE INVESTMENT RISK OF NIPSCO OR UTILITIES GENERALLY IS INCREASING?

A No. The VIX is a broader-based market index of stock price volatility, and not that of subgroups within the market generally, and certainly not applicable to the utility subsector. Utility securities are generally regarded as a component of "safe haven" investments, and the market generally flocks to low-risk sectors during periods of broader economic distress. The VIX index may indicate greater risk in the overall market but that does not indicate a similar change in investment risk for lower-risk regulated utility companies.

Q IS THERE A WAY TO OBSERVE CHANGES IN MARKET CAPITAL COST TO ASSESS THE RISK PREMIUM DEMANDED BY MARKET PARTICIPANTS?

A Yes. This can largely be observed by gauging the risk premiums that can be observed from changes in utility bond yields to Treasury yields. The yield spread between utility bond yields and Treasury bond yields currently, relative to long-term historical periods, does not support Mr. Rea's contention that NIPSCO's cost of equity capital has increased. Another means is to look at utility stock yields, relative to utility bond yields, to gauge whether or not securities of increasing level of risk are implicitly indicating greater levels of equity risk premiums.

A comparison of the yield spread for utility bonds to Treasury bonds is summarized in Table 4 below.

TABLE 4

Comparison of Yield Spreads Over Treasury Bonds

	Utility		Corporate	
	A	**Baa**	**Aaa**	**Baa**
LT Average	1.50%	1.93%	0.84%	1.93%
2017 Spread	1.10%	1.48%	0.85%	1.55%
2018 Spread	1.14%	1.56%	0.82%	1.69%
2020 YTD	1.57%	1.98%	1.06%	2.24%

Source: Attachment MPG-1

Note:
2020 data through September.

As shown in Table 4 above, the yield spread between utility bond yields and Treasury bond yields indicates a spread that is reasonably aligned with average historical spreads, albeit spreads that are higher than that prevailed in 2017 and 2018, the period of NIPSCO's last electric and gas rate cases. On Attachment MPG-2, a more recent 13-week yield spread in 2020 is below the 2020 year-to-date average spread.

The current yield spread of 1.57% for A-rated utility bonds relative to Treasury bonds is slightly higher than the long-term spread of 1.50%. Similarly, the spread for Baa utility bond yields is slightly higher but comparable to historical bond yield spreads. However, and importantly, utility Baa yield spreads have narrowed in comparison to corporate bond yields. This supports the expectation and belief that utility bonds are perceived as a component of the "safe haven" investments for turbulent economic times (like now), and have supported stronger valuations for utility securities than that of general corporate securities.

A comparison of utility bond yield spreads to utility stock yields also shows that utility stock valuations have changed with the reductions in interest rates.

Q MR. REA DEVELOPED A PROJECTED DCF RETURN ON THE S&P 500 IN HIS CAPM. DOES THIS MARKET DCF ESTIMATE SUPPORT A FINDING THAT CAPITAL MARKET COSTS HAVE INCREASED?

A No. I summarize Mr. Rea's results in Table 5 below, along with adjustments to his estimates in Column 3.

TABLE 5

NIPSCO Rea S&P 500 DCF and Bond Yields

Description	S&P 500 DCF Yield	S&P 500 DCF Growth	S&P 500 DCF DCF	Projected Treasury Bond	"A-Rated" Utility Bond
	(1)	(2)	(3)	(4)	(5)
Last Electric Case (Cause No. 45159)	1.99%	11.67%	13.66%	4.08%	5.41%
Last Gas Case (Cause No. 44988)	2.09%	10.28%	12.37%	4.19%	5.49%
Current Case	1.84%	9.63%	11.47%	2.62%	4.01%

Sources:
Cause No. 45159, Petitioner's Exhibit No. 15, Attachment 15-A, Schedules 7 and 8.
Cause No. 44988, Petitioner's Exhibit No. 13, Attachment 13-A, Schedules 7 and 8.
Petitioner's Exhibit No. 4, Attach. 4-A, Schedule 6.

As shown in Table 5 above, Mr. Rea's data underlying his CAPM analysis does not support his notion that capital market costs today have increased relative to the time he filed his testimony in NIPSCO's last electric and gas cases. Specifically, as shown in Table 5 above, Mr. Rea's projected DCF return on the market has decreased by over 200 basis points since NIPSCO's last rate case, and approximately 90 basis points since its last gas case. Further, his market data shows a significant decline in the "projected" Treasury bond yields over the next five years. Indeed, projected

Treasury bond yields five years out are 150 to 160 basis points lower in this case than they were in NIPSCO's last electric and gas case. Further, Mr. Rea's projection for A-rated utility bond yields is also much lower in this case than it has been in the last cases. As shown in Table 5 above, Mr. Rea's projected A-rated utility bond yield of 4.01% is approximately 140 basis points lower than his projections offered in his electric (5.41%) and gas (5.49%) case testimony.

All of this data indicates a decline in capital market costs in the current case, compared to Mr. Rea's testimony filed in NIPSCO's electric and gas rate cases.

I.F. COVID-19 PANDEMIC

Q HAS THE COMMISSION TAKEN SPECIFIC MEASURES TO HELP PROTECT NIPSCO'S ABILITY TO FULLY RECOVER ITS COST OF SERVICE DURING THE ECONOMIC DISTRESS CAUSED BY THE COVID-19 PANDEMIC?

A Yes. The Commission has implemented measures that prohibit NIPSCO from disconnecting service for customers that are not paying their bill through August of 2020. While this is an extraordinary measure, and exposes NIPSCO and other Indiana utilities to increases in uncollectible accounts expense, and waiver of certain utility fees, the Commission also approved regulatory mechanisms that allow utilities to defer uncollectible accounts, and certain fees, and recover these from customers prospectively. Customers that pay their bills will effectively make the utility whole and protect it from customers that are not able to pay their bills during the national economic downturn.[6]

The Commission's regulatory mechanisms, while protecting customers to receive essential utility services, were done in concert with the implementation of

[6] June 29, 2020 Order in Cause Nos. 45377 and 45380 at 4 and 6.

regulatory mechanisms that preserved the utility's ability to fully recover its cost of service. For these reasons, the economic turmoil caused by the current worldwide pandemic has caused distress for NIPSCO and all of its customers, but the Commission has mitigated NIPSCO's risk considerably with the implementation of these regulatory mechanisms.

Q HAS THE MARKET GENERALLY OPINED ON THE IMPACT OF THE INVESTMENT RISK OF REGULATED UTILITY COMPANIES DURING THE CURRENT ECONOMIC DISTRESS CAUSED BY THE COVID-19 PANDEMIC?

A Yes. The global economy has faced the extraordinary challenges of the novel Coronavirus, which led to nearly a complete shutdown of the global economy. This unprecedented event has impacted all sectors and capital markets. Regarding regulated utilities, S&P's outlook is that utilities will handle the short-term economic distress caused by the pandemic. S&P made the following statements:

> **Key Takeaways**
>
> - S&P Global economists' now forecast a global recession this year, with the U.S. expected to post a seasonally adjusted second quarter contraction of about 6% before recovery begins in the second half of the year.
>
> - We believe that the majority of North American regulated utilities are well positioned to handle the immediate impact of COVID-19. However, the pandemic could negatively affect a few outliers and those issuers already facing downside ratings pressure prior to the arrival of the coronavirus.
>
> - Some electric utilities with disproportionate exposure to commercial and industrial class of customers could be vulnerable to reduced sales volumes, absent any regulatory counter mechanisms such as decoupling.[7]

[7] *S&P Global Ratings*: "North American Regulated Utilities Face Additional Risks Amid Coronavirus Outbreak," March 19, 2020, at 1.

Moody's also opines that there may be delays in rate case decisions due to COVID-19, but views the regulated utilities resilient to withstand the current economic distress caused by the pandemic. Specifically, Moody's states:

> When considering the short-term credit implications of coronavirus-related regulatory delays, we will view any modest weakening in financial metrics as temporary and not detrimental to long-term credit quality, unless it is accompanied by a more contentious regulatory or political environment. We will continue to expect utilities to make proactive financial policy adjustments if the dip is material, or appears likely to remain for an extended period of time. For now, we expect state regulatory commissions to continue to provide a broad suite of timely cost recovery mechanisms and to address current challenges like lost revenue and incremental expenses. As a result, we think the overall relationship with the sector remains supportive.
>
> * * *
>
> **We will generally try to see through one- or two-year drags on financial metrics due to these delays.** We assume that the pandemic will be contained by then, that economic activity will recover and that the rate increases will eventually be approved, including some of the lost revenues associated with the delay. However, if the US economic downturn were to be protracted, it could have negative credit implications for certain utilities, such as those that have been operating with leverage that we had already considered high before the outbreak.[8]

Similarly, Fitch expects utilities to weather the pandemic economic turbulence. Fitch states:

> **Fitch's Sector Outlook: Stable**
> Fitch Ratings' stable outlook embeds an expectation that sector credit metrics will begin to stabilize in 2020, driven by an increase in FFO after the record capex in 2019 and conclusion of a majority of tax reform-related refunds. Low commodity prices and interest rates, O&M cost savings, in part due to the ongoing transition to cleaner generation mix, and tax refunds are providing ample headroom to utilities to seek recovery for capital investments without undue pressure on customer bills.
>
> * * *

[8] *Moody's Investors Service Sector Comment*: "Regulated Electric, Gas and Water Utilities – US: Coronavirus outbreak delays rate cases, but regulatory support remains intact," April 6, 2020.

> **Rating Outlook: Stable**
> With approximately 88% of ratings on Stable Outlook, we expect limited rating movement in 2020.[9]

Q IS THERE SPECIFIC EVIDENCE ABOUT HOW NIPSCO'S INVESTMENT RISK HAS BEEN IMPACTED BY THE ECONOMIC TURMOIL CAUSED BY THE COVID-19 PANDEMIC?

A In a recent credit report from Moody's, the agency did note its concern about the impact on the economic fallout of NIPSCO's service territory generally, and NIPSCO itself. However, it did note an expectation that due to the positive regulatory treatment offered by the Commission to NIPSCO, that NIPSCO is expected to recover from the economic effects of the pandemic intact. Specifically, Moody's states as follows:

> NIPSCO's rating is constrained by its parent NiSource. We see high leverage in the consolidated capital structure, with an estimated 30% of consolidated debt at the parent level, and a relatively unrestricted ability to move cash across the corporate family. Over the next few years, we expect some weakening in NIPSCOs historically strong credit metrics as the company invests in renewable generation to replace coal generation.
>
> The rapid spread of the <u>coronavirus outbreak, severe global economic shock, low oil prices, and asset price volatility are creating a severe and extensive credit shock across many sectors, regions and markets</u>. The combined credit effects of these developments are unprecedented. We regard the coronavirus outbreak as a social risk under our ESG framework, given the substantial implications for public health and safety. We <u>expect NIPSCO to be relatively resilient to recessionary pressures</u> related to the coronavirus because of its <u>fully rate regulated operations</u>.[10]

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[9] *Fitch Ratings*: "Fitch Ratings 2020 Outlook: North American Utilities, Power & Gas," December 4, 2019.

[10] *Moody's Investors Service, Credit Opinion*: "Northern Indiana Public Service Company, Update to credit analysis," July 29, 2020 at 1, emphasis added.

I.G. Surcharges Impact on Investment Risk

Q HAVE THERE BEEN ANY COMMENTS BY CREDIT RATING AGENCIES CONCERNING NIPSCO'S COST RECOVERY RISK AS AFFECTED BY THE REGULATORY TREATMENT IT IS AFFORDED BY OPERATING IN THE STATE OF INDIANA?

A Yes. The Commission generally is regarded as supportive of NIPSCO's ability to recover its cost due to favorable regulatory treatments. This has resulted in a "Stable" outlook for NIPSCO's current Baa1 credit rating from Moody's. Related to the actual regulatory treatment afforded to NIPSCO Moody's states as follows in support of this "Stable" credit rating outlook:

> We view Indiana's regulatory environment as generally credit supportive of NIPSCO. The utility has access to a suite of attractive tracker and rider mechanisms that allow for timely recovery of both capital investments and expenses. NIPSCO recovers its largest cost component, fuel and power purchase costs, through regular fuel pass-through adjustments. It also benefits from mechanisms that cover electric energy efficiency costs, MISO RTO non-fuel costs and revenues, resource capacity charges, and environmental related costs.
>
> NIPSCO's environmental cost trackers (ECT) provide for recovery of its environmental investments, of particular importance to the company given its sizeable coal generation fleet. The ECT allows the utility to recover AFUDC and a return on environmental compliance capital investment projects through an environmental cost recovery mechanism (ECRM). Similarly, the related operation and maintenance and depreciation expenses incurred once the environmental facilities become operational are recovered through an environmental expense recovery mechanism (EERM).
>
> NIPSCO also utilizes Indiana's Transmission, Distribution and Storage System Improvement Charge (TDSIC) for infrastructure improvement expenditures focused on safety, reliability, and modernization. It allows 80% of the investment to be recovered through a semi-annual tracker adjustment while the remaining 20% is deferred until the next rate case.[11]

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[11] *Id*. at 4.

Similarly S&P stated the following:

> **Business Risk: Excellent**
>
> Our assessment of NIPSCO's business risk largely reflects its lower-risk regulated and vertically integrated electric and gas distribution operations, larger customer base with about 800,000 gas and 500,000 electric customers, and its generally constructive regulatory framework. We expect the company will continue to effectively manage regulatory risk through future rate case filings and continued use of regulatory riders for environmental, transmission, and distribution costs. <u>The use of these riders reduces the company's regulatory lag and allows it to generally earn close to its allowed return on equity</u>. Currently, the company's generation fleet largely consists of coal-fired generation, indicative of potentially higher environmental risks. However, we expect the company will gradually replace its coal generation with environmentally friendlier generation, eventually reducing these risks.[12]

I.H. Incremental Return on Equity Estimates

Q IN LIGHT OF YOUR ANALYSIS, HAS MR. REA SHOWN THAT CHANGES IN CAPITAL MARKET CONDITIONS, SUBSEQUENT TO THE LAST RATE CASE, SUPPORT AN INCREASE IN NIPSCO'S AUTHORIZED RETURN FOR TDSIC PURPOSES TO 10.7%?

A No. The proposal in this proceeding to increase NIPSCO's return on equity is unsupported and inconsistent with current market conditions, and if granted would result in unreasonable and excessive charges to NIPSCO's customers. My analysis shows that the base rate return on equity allowed in NIPSCO's last rate case is higher than the level indicated by the current capital market, financial metrics and NIPSCO's risk profile. If the Commission concludes that evidence of current market conditions should be considered as "other information" bearing on the determination of an appropriate return for TDSIC purposes, as discussed at pages 27-28 of the Final Order

[12] *S&P Global RatingsDirect*: "Northern Indiana Public Service Co. LLC," March 5, 2020, at 4, emphasis added.

in Cause No. 45330, I recommend that the authorized TDSIC return for NIPSCO be reduced from the current base rate return, not increased as proposed by Mr. Rea.

Q BASED ON YOUR ASSESSMENT OF MARKET CAPITAL COSTS, AND YOUR REVIEW OF MR. REA'S UPDATED RETURN ON EQUITY STUDIES, WHAT MARGINAL COST OF EQUITY DO YOU BELIEVE IS APPROPRIATE BASED ON CURRENT CAPITAL MARKET COSTS?

A As outlined in my Appendix B, I believe Mr. Rea's analyses when adjusted to remove unreasonable data and inappropriate methodologies, and based purely on observable market evidence, indicate a fair return for NIPSCO in the range of 9.0% to 9.4%. This 9.4% I would note also is in line with the 2020 industry authorized returns on equity for electric and gas utility companies in the range of 9.40% to 9.45%.[13] As such, if the Commission determines an adjustment to reflect current market conditions is appropriate as suggested by NIPSCO, I recommend the Commission award NIPSCO a return on equity limited to no more than a 9.4% return on equity for purposes of computing TDSIC revenue requirements.

[13] *S&P Global Market Intelligence, RRA Regulatory Focus*, "Major Rate Case Decisions -- January - September 2020," October 20, 2020 at page 1.

II. ADJUSTMENTS FOR DOUBLE RECOVERY AND SHIFTED RISK

II.A. NIPSCO'S Proposal

Q IN THE ORDER APPROVING NIPSCO'S GAS TDSIC PLAN, THE COMMISSION INVITED THE PARTIES TO PRESENT EVIDENCE IN THIS PROCEEDING TO SUPPORT THE DETERMINATION OF AN APPROPRIATE RETURN FOR TDSIC PURPOSES. OTHER THAN MR. REA'S ANALYSIS OF CURRENT MARKET CONDITIONS, HAS NIPSCO PRESENTED ANY PROPOSALS ADDRESSING RATEMAKING CONSIDERATIONS SPECIFIC TO THE TDSIC MECHANISM?

A No. NIPSCO is proposing a sizable increase to the base rate return allowed in its last rate case, primarily on the premise that the economic disruption caused by the COVID-19 pandemic has resulted in higher risk for NIPSCO's operations, but NIPSCO has not proposed any adjustment based on the differences between the rate treatment of TDSIC investments as opposed to costs recovered through base rates.

Q DO YOU BELIEVE THERE ARE MATERIAL DIFFERENCES BETWEEN TDSIC RECOVERY AND BASE RATE RECOVERY THAT SUPPORT A DISTINCT RETURN FOR TDSIC PURPOSES?

A Yes. In the Final Order in Cause No. 45330, the Commission quoted a recent Order approving a TDSIC Plan for Indianapolis Power & Light (IPL), which identified two relevant considerations.[14] Specifically, the Commission noted the "continued concerns with double recovery" and "concerns with the shifting of risks based on plan approval." In both respects, there are ratemaking considerations unique to the TDSIC mechanism that support a distinct TDSIC return on equity that differs from the return on equity

[14] *See* July 22, 2020 Order in Cause No. 45330 at 27-28; March 4, 2020 Order in Cause No. 45264 at 27.

allowed for purposes of base rates. In both instances, the considerations support a downward adjustment to the base rate return on equity.

II.B. Double Recovery

Q PLEASE DESCRIBE THE CONCERN RELATING TO DOUBLE RECOVERY AS REFERENCED BY THE COMMISSION IN THE ORDER APPROVING NIPSCO'S GAS TDSIC PLAN.

A For projects that involve replacement of existing system assets, the TDSIC mechanism provides for recovery of incremental costs associated with the new asset, including depreciation expense, pretax return, O&M, taxes, and carrying costs. However, return associated with the removed asset that is being replaced is also embedded in NIPSCO's base rates. In the absence of an appropriate netting mechanism, NIPSCO would receive duplicative recovery for successive assets performing the same functions in the same locations, once through return embedded in base rates for replaced assets and again through added return under the TDSIC mechanism for the replacement assets.

Q HAS NIPSCO PROPOSED AN APPROPRIATE NETTING MECHANISM IN THIS CASE TO OFFSET THE DOUBLE RECOVERY ASSOCIATED WITH ASSET REPLACEMENTS?

A No. In Cause No. 45330, NIPSCO's position was that it was not required to implement any netting or offset. Consistent with that view, NIPSCO has not proposed any kind of netting mechanism in this proceeding.

Q IS AN ADJUSTMENT TO THE AUTHORIZED RETURN FOR TDSIC PURPOSES AN APPROPRIATE APPROACH TO ADDRESS THE LACK OF A NETTING PROPOSAL BY NIPSCO?

A The most efficient and precise method to correct the double recovery associated with asset replacements in a TDSIC Plan would be to require the utility to implement a netting mechanism that would remove the double recovery. I explain what such a mechanism would include subsequently in my testimony. In the event, however, that the Commission concludes it cannot or should not order netting in the absence of a voluntary proposal by the utility, an adjustment to the authorized return specific to TDSIC recovery would be an alternative method of addressing the excessive charges arising from double recovery for asset replacements in base rates and the TDSIC tracker.

Q IN THE ABSENCE OF A NETTING MECHANISM, WHAT ADJUSTMENT TO THE TDSIC-SPECIFIC RETURN WOULD BE APPROPRIATE TO ACCOUNT FOR THE DOUBLE RECOVERY RELATING TO ASSET REPLACEMENTS?

A An appropriate adjustment to return on equity for TDSIC purposes would have the same revenue impact as an appropriate netting mechanism, as described later in my testimony. In the context of NIPSCO's Gas TDSIC Plan, I recommend a downward adjustment of 20 basis points relative to NIPSCO's base rate return on equity, to account specifically for the absence of any netting mechanism for replaced assets.

II.C. Shifted Risk

Q PLEASE DESCRIBE THE SHIFTED RISK CONCERN ARISING FROM APPROVAL OF A TDSIC PLAN.

A A basic principle of utility ratemaking is that a regulated rate of return should be commensurate with that of businesses having corresponding risks and uncertainties. A reduction in the utility's risk, consequently, is properly reflected in a lower authorized return on equity. The return on equity that the Commission allowed in NIPSCO's most recent rate case was found appropriate in the context of the risks faced by NIPSCO with respect to the costs recovered in base rates. The TDSIC mechanism, however, significantly alters the cost recovery risk faced by NIPSCO, and shifts substantial risk to NIPSCO's customers. Because NIPSCO's risk has been largely eliminated by approval of the TDSIC Plan, in contrast to the risks reflected in base rates, a lower return on equity is reasonable and appropriate in the context of TDSIC cost recovery.

Q WHY DO YOU BELIEVE THAT THE IMPLEMENTATION OF THE TDSIC MECHANISM WILL REDUCE NIPSCO'S COST RECOVERY RISK?

A I would note that all trackers reduce a utility's risk profile. The TDSIC tracker reduces NIPSCO's risks in a number of ways. Through the adjustment mechanism NIPSCO will be allowed to recover 80% of significant, $948 million, investments in TDSIC-related equipment outside of a general rate case.

Under the TDSIC mechanism, the planned capital investments are preapproved for rate recovery up to the authorized cost estimates. With respect to the 80% subject to tracking, the TDSIC statute states that rate adjustments to recover authorized expenditures are "automatic," thus removing the risk of cost recovery disallowance. The use of a tracking mechanism accelerates recovery compared to rate case treatment, and thereby mitigates regulatory lag and improves utility cash flows. The process further permits CWIP recovery, in contrast to traditional ratemaking in which a system asset must be placed in service and must be used and useful before rate recovery is available. The opportunity to recover investment and earn a return while construction is ongoing again serves to accelerate recovery, reduce risk, and enhance cash flow. Moreover, in contrast to rate case recovery, the tracker is subject to reconciliation in subsequent filings, eliminating risk relating to load volatility and errors in the projections used to compute unit rates. With regard to the 20% recoverable in the next rate case, NIPSCO is allowed to book a regulatory asset with assurance of recovery in its next rate case, again eliminating the risk of disallowance through an after-the-fact prudence review. In connection with all of the investments, NIPSCO recovers indirect capital, AFUDC, and post-in service carrying costs, providing compensation for all expenditures from the date they are made through the point of rate recovery. In short, before the first dollar of capital is put forward, investors have statutory assurance of full rate recovery up to the authorized estimates on an accelerated basis, without risk of disallowance.

Q IN LIGHT OF THE REDUCTION IN RISK TO NIPSCO INVESTORS, IS THERE A CORRESPONDING INCREASE IN RISK TO NIPSCO RATEPAYERS ASSOCIATED WITH THE APPROVED TDSIC PLAN?

A Yes. NIPSCO has already secured preapproval for the TDSIC Plan up to the authorized expenditures, based on projected incremental benefits presented by NIPSCO. Because the rate recovery is “automatic” under the TDSIC mechanism, ratepayers do not have the protection of any further prudence review once the investments have been made. NIPSCO ratepayers will not have the opportunity to question whether TDSIC Plan investments were necessary, reasonable or excessive in light of actual experience. NIPSCO will be able to recover TDSIC costs in rates, even if the projected benefits anticipated by NIPSCO do not actually materialize or, prove to be less valuable than NIPSCO's original projections. Within the scope of the approved TDSIC Plan, the risk of rate recovery and successful realization of anticipated benefits has shifted away from NIPSCO and now rests on NIPSCO's customers.

Q HOW DO YOU RESPOND TO MR. REA'S DISCUSSION OF RISK RELATING TO APPROVAL OF THE TDSIC PLAN AT PAGES 22 TO 26 OF HIS TESTIMONY?

A Mr. Rea misconstrues the issue by arguing as if the question involved a proposal to adjust the return on equity embedded in NIPSCO's base rates. That is not the case. As explained in the orders approving the NIPSCO Gas TDSIC Plan and IPL's TDSIC Plan, the consideration of "other information" to determine an appropriate TDSIC return is solely for purposes of computing the TDSIC costs eligible for recovery under the TDSIC mechanism. Establishing a distinct TDSIC return would not alter the existing return on equity included in NIPSCO's current base rates. As such, the question is not whether and how approval of the TDSIC Plan impacts NIPSCO's company-wide risk for purposes of determining a reasonable base rate return, as Mr. Rea assumes, but rather how the risks associated with TDSIC recovery differ from the risks reflected in base rate recovery. Furthermore, NIPSCO's prior TDSIC Plan, which was in place at the time of the last rate case, involved a lower level of investment, with only $645 million in investment when it was terminated in 2019, in contrast to the $948 million preapproved in the current Plan. In addition, Mr. Rea's contention that TDSIC spending increases NIPSCO's risk and poses a threat of negative cash flows is framed under the fictitious assumption that the only alternatives are rate case treatment or no TDSIC recovery at all. To the contrary, the relevant comparison is between TDSIC recovery based on the same return on equity allowed for base rates as opposed to TDSIC recovery based on a distinct return that reflects the elimination of risk under the TDSIC mechanism.

Q WHAT FURTHER ADJUSTMENT TO THE AUTHORIZED RETURN ON EQUITY FOR TDSIC PURPOSES DO YOU RECOMMEND TO ACCOUNT FOR THE CONCERNS RELATING TO AUTOMATIC RECOVERY AND REALLOCATION OF RISK?

A As explained previously, I believe a reduction to 9.4% would be reasonable and appropriate solely to account for current capital market costs for utility companies, without any accounting for the double recovery concern or the change in risk profile associated with TDSIC investments. For the reasons explained in more detail previously in my testimony, the lack of any netting proposal by NIPSCO to address the double recovery arising from continued base rate recovery for removed assets concurrent with TDSIC recovery for replacement assets calls for a further downward adjustment of 20 basis points to the authorized return on equity for TDSIC purposes. But additionally, the approval of the TDSIC Plan removes substantial risk from NIPSCO investors with respect to almost $1.0 billion in system investments and shifts the risk to NIPSCO ratepayers, who are subject to automatic rate recovery without regard to NIPSCO's success in achieving the projected benefits, warranting a further downward adjustment of another 20 basis points. To reflect current capital market conditions, the lack of a netting proposal by NIPSCO to address the double recovery concern, and in combination with the shifted risk associated with TDSIC investments, I recommend a TDSIC-specific return on equity at the low-end of my range, or 9.0%. My recommendation, accordingly, is that the Commission determine that the appropriate pretax return on equity specific to the calculation of TDSIC costs should be 9.0%. Even if the Commission decides not to update the return on equity approved in NIPSCO's last rate case to account for changes in capital market conditions, a distinct TDSIC return on equity reflecting the double recovery and shifted risk adjustments should still be established, resulting in a 9.45% pretax return on equity for purposes of computing TDSIC revenue requirements.

III. DEPRECIATION NETTING

Q IS THERE AN ALTERNATIVE APPROACH TO ADDRESS THE DOUBLE RECOVERY ISSUE, OTHER THAN AN ADJUSTMENT TO THE ALLOWED RETURN FOR TDSIC PURPOSES AS DISCUSSED EARLIER IN YOUR TESTIMONY?

A Yes. Making a downward adjustment to return on equity for purposes of computing TDSIC revenue requirements is an indirect approach to correcting the underlying issue with double recovery. The Final Order in Cause No. 45330 identifies that indirect approach as an appropriate measure, but the more direct way to address the issue and prevent over-recovery by NIPSCO is to require implementation of an appropriate netting mechanism. In the event that the Commission concludes it can and should require netting to prevent double recovery, I have developed an appropriate netting mechanism that will eliminate the double recovery.

Q WOULD YOUR NETTING PROPOSAL INVOLVE ADJUSTMENTS TO THE MEASUREMENT OF DEPRECIATION EXPENSE INCLUDED IN THE TDSIC REVENUE REQUIREMENT FOR TRANSMISSION AND DISTRIBUTION FACILITIES?

A Yes. On Attachment 1, Schedule 4, the Company outlines its development of depreciation expense for transmission TDSIC investments (Attachment 1, Schedule 4, page 1) and distribution investments (Attachment 1, Schedule 4, page 2). These depreciation expense lines are picked up on total TDSIC revenue requirement on Attachment 1, Schedule 5. As developed on Attachment 1, Schedule 4, the Company develops recoverable depreciation expense based on actual expense in the historical period, plus projected expense. The Company's projected expense reflects plant additions for transmission and distribution TDSIC investments. Depreciation expense is based on specific FERC accounts for transmission investments (367, 369 and 370), distribution plant investments (376, 380 and 383) and storage (353, 354, 356 and 361).[15]

Q IS THE COMPANY'S DEVELOPMENT OF THE DEPRECIATION EXPENSE INCLUDED IN THE TDSIC REVENUE REQUIREMENT REASONABLE?

A No. The Company's inclusion of depreciation expense should reflect a netting of depreciation expense increases, offset by reductions in depreciation expense caused by plant retirements. Specifically, there are certain transmission and distribution plant that will be taken out of service as that plant is replaced by new investments where the cost is covered under the TDSIC surcharge. As such, the Company's Attachment 1, Schedule 4, pages 1, 2 and 3 should include a line item that reflects plant retirements

[15]Attachment MPG-3.

for the specific FERC accounts under which the transmission, distribution, and storage TDSIC investments will be made. This will produce a net change in depreciation expense reflecting both additions and retirements to the FERC accounts which will drive changes in the Company's overall depreciation expense for these facilities. Again, this is consistent with measuring an incremental revenue requirement as opposed to simply identifying increased costs for line item costs included in the TDSIC.

Q ARE THERE ANY OTHER ADJUSTMENTS NEEDED TO THE COMPANY'S PROPOSED TDSIC REVENUE REQUIREMENTS TO REFLECT DEPRECIATION NETTING?

A Yes. The Company's development of the capital costs, or rate base value of TDSIC investments, also should be corrected to reflect the change in net plant for the FERC accounts in which the TDSIC investments will be recorded. These net plant accounts will reflect the roll-forward of historical depreciation expense recoveries in base rates, offset by incremental investments that will be recorded in these plant investments which will be recovered in the TDSIC surcharge. The total investments in these respective FERC accounts then will reflect gross plant additions, offset by the roll-forward of accumulated depreciation reserves.

To eliminate the double recovery, it is not enough only to track incremental plant investments and the change in depreciation reserve related to only these plant investments. That alone would not reflect depreciation expense paid by customers in base rates for these same FERC accounts that will provide the Company recovery of these plant investments.

Q DO YOU HAVE AN ATTACHMENT THAT OUTLINES THE ANNUAL DEPRECIATION EXPENSE RECOVERED BY THE COMPANY IN ITS BASE RATES FOR THESE SPECIFIC FERC ACCOUNTS?

A Yes. As outlined on my Attachment MPG-3, I show annual depreciation expense built up for transmission, distribution and storage plant to be $8.258 million, $36.746 million and $0.770 million in 2019, respectively. These costs should be rolled forward to the respective period where the TDSIC rate base is measured in order to track changes in net plant values of TDSIC-related investments. This is consistent with measuring the incremental revenue requirement and ensuring that customers' rates and total charges are reasonable, while the Company is provided an opportunity to earn a revenue requirement that fully compensates it for its total investment cost.

Q ARE YOU PROPOSING BOTH THAT THE APPROVED RETURN FOR TDSIC PURPOSES BE ADJUSTED TO ADDRESS THE DOUBLE RECOVERY ISSUE AND IN ADDITION THAT THE NETTING MECHANISM YOU DESCRIBE BE IMPLEMENTED?

A No, those are alternative approaches to correcting for the double recovery associated with asset replacements. The more direct method is to implement the netting proposal, but in the event the Commission determines it cannot or should not require netting, the adjustment to TDSIC return is another way to mitigate the excessive charges to customers arising from double recovery for asset replacements.

IV. TDSIC COST OF DEBT

Q WHAT COST OF DEBT DOES NIPSCO PROPOSE BE USED IN DEVELOPING A TDSIC REVENUE REQUIREMENT?

A NIPSCO's Attachment 2, Schedule 1 develops its requested overall rate of return used to develop its TDSIC revenue requirement as developed on its Attachment 1, Schedule 2. That overall rate of return reflects an embedded cost of long-term debt of 4.71%, stated as of June 30, 2020.

Q HAVE THERE BEEN SIGNIFICANT CHANGES IN NIPSCO'S EMBEDDED COST OF DEBT OVER TIME?

A Yes. NIPSCO's embedded cost of debt is significantly higher than its current market or marginal cost of debt. Due to refinancings and issuances of new debt, NIPSCO's embedded debt cost has been declining significantly. However, the embedded debt cost reflected in its base rates has been held constant. Specifically, NIPSCO observed that its embedded debt cost at June 30, 2020 is 4.71%. This updated embedded debt cost is significantly lower than the embedded debt cost NIPSCO used to set its electric base rates in 2018 of 4.97% (December 31, 2019), and its base rates for gas delivery of 5.25% (December 31, 2018).[16]

NIPSCO's embedded cost of debt in its last gas and electric cases were 5.25% (2018) and 4.97% (2019), respectively. NIPSCO's cost of debt decreases as it refinances embedded cost of debt and issues new debt to finance new capital investments.

[16]Cause No. 45159, Rea Direct Testimony Attachment 13-A, Schedule 10; and Cause No. 44988, Rea Direct Testimony Attachment 15-A, Schedule 2.

NIPSCO's marginal cost of debt tracks its current bond rating in the marginal cost of issuing new debt for utilities with that bond rating. NIPSCO's current bond rating from Moody's is Baa1.[17] The marginal cost of Baa-rated utility debt for 2020, as shown on my Attachment MPG-4, is 3.47%. This is over a 155 basis point reduction from NIPSCO's embedded cost of debt at June 30, 2020 of 4.71%.

Q WHY DOES NIPSCO'S EMBEDDED COST OF DEBT CHANGE AFTER THE RATE CASE IS COMPLETED?

A As NIPSCO undertakes new capital investments, they will be funded by refinancings of existing debt, or new bond issues to produce funding for new capital investments. As such, its incremental cost of debt is driven by its marginal cost, which aligns with the incremental revenue requirement associated with TDSIC investments. More importantly, NIPSCO's embedded cost of debt is already included in its base rates as reflected in its last gas and electric rate cases, both of which include debt costs that exceed NIPSCO's more recent embedded cost of debt estimate.

In an effort to more accurately track NIPSCO's incremental revenue requirement for its incremental TDSIC investments, I recommend the TDSIC tracker include NIPSCO's incremental debt costs measured from the time the TDSIC surcharge is put into effect, and is based on the weighted average debt issued by NIPSCO from that point forward over the period the TDSIC Rider mechanism is in effect.

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[17] *Moody's Investors Service, Credit Opinion*: "Northern Indiana Public Service Company, Update to credit analysis," July 29, 2020.

V. PROJECTED DEPRECIATION AND PROPERTY TAXES

Q IS NIPSCO PROPOSING TO ALTER THE MANNER IN WHICH IT RECOVERS DEPRECIATION AND PROPERTY TAXES THROUGH THE TDSIC TRACKER?

A Yes. As described in Ms. Dousias's testimony at pages 13-15, NIPSCO is seeking authority to include depreciation and property tax expense in its TDSIC revenue requirements on a projected basis, subject to reconciliation. The stated justification is to reduce the regulatory lag associated with cost recovery on a historical basis. Under NIPSCO's proposal, the projected expenses will be reconciled in a future filing to the actual amounts through a pass-through to customers of variances based on actual expenses incurred.

Q IS THAT PROPOSAL A CHANGE FROM THE WAY NIPSCO HAS RECOVERED DEPRECIATION AND PROPERTY TAX EXPENSE IN ITS TDSIC PROCEEDINGS PREVIOUSLY?

A Yes. To the best of my knowledge, NIPSCO to date has recovered actual reported depreciation and property tax expenses as incurred, through its TDSIC trackers for both gas and electric rates. The proposal to shift from recovery of actual incurred expenses to projected expenses is a change to its longstanding TDSIC practice that NIPSCO is requesting for the first time in this proceeding.

Q IS THE RATE RECOVERY OF PROJECTED COSTS NOT YET INCURRED A STANDARD FEATURE OF TRADITIONAL RATEMAKING?

A No. Traditional ratemaking in Indiana follows the "used and useful" principle, by which a system asset must be completed and placed in service before the utility may seek recovery for the associated costs. In some circumstances, such as some statutory tracking mechanisms, recovery is permitted for construction work-in-progress or CWIP investments, prior to the asset being placed in service. My understanding is that the TDSIC statute permits CWIP ratemaking treatment. Even where CWIP ratemaking is appropriate, however, the standard approach is for the utility to base rate recovery on actual costs that it can report as having been incurred. Preapproval under the TDSIC mechanism permits the utility to seek periodic rate adjustments to recover costs as they are actually incurred, including costs associated with approved projects that are still under construction, but such preapproval is distinct from imposing rate adjustments to recover projected costs not yet incurred.

Q DOES NIPSCO CITE TO ANY PROVISION IN THE TDSIC STATUTE THAT AUTHORIZES RATE ADJUSTMENTS TO RECOVER PROJECTED COSTS THAT HAVE NOT YET BEEN ACTUALLY INCURRED?

A Not that I could see. Ms. Dousias asserts that the change to recovery of projected expenses for depreciation and property taxes would reduce regulatory lag, but she does not point to any provision in the TDSIC statute authorizing that ratemaking approach. She also states that a similar approach has been allowed for NIPSCO's separate trackers relating to federally mandated expenses, but those trackers involve a different statute and have their own procedural history. In that respect, Ms. Dousias again does not base the proposal here on the terms of the TDSIC statute.

Q ARE YOU AWARE OF ANY PROVISION IN THE TDSIC STATUTE AUTHORIZING RATE ADJUSTMENTS BASED ON PROJECTED EXPENSES NOT YET INCURRED?

A No. I am not an attorney and cannot offer opinions regarding the proper interpretation of statutory language, but the definition of "TDSIC costs" at Section 7 of the TDSIC Statute is framed in terms of "costs incurred with respect to eligible transmission, distribution, and storage system improvements incurred both while the improvements are under construction and post in service." The reference to "incurred" costs is consistent with traditional ratemaking, where rate recovery must be predicated on the reported costs that the utility has actually incurred.

Q DO YOU AGREE WITH MS. DOUSIAS THAT RECOVERING DEPRECIATION AND PROPERTY TAX EXPENSES ON A PROJECTED BASIS WOULD HAVE THE EFFECT OF REDUCING REGULATORY LAG?

A Yes, but that does not mean the complete elimination of regulatory lag is an overriding priority. The TDSIC mechanism, as applied historically by NIPSCO since 2014, already includes significant features that reduce regulatory lag. NIPSCO is allowed to implement rate adjustments to recover TDSIC costs in between rate cases, facilitating more timely recovery of TDSIC investments. Under the TDSIC mechanism, NIPSCO is allowed to recover incurred costs for assets that have not yet been placed in service, providing more accelerated rate recovery than would be permitted under the used-and-useful rule. In addition, NIPSCO recovers carrying costs on TDSIC investments from the time the expenditures are made, further mitigating the impact of regulatory lag under traditional ratemaking. NIPSCO has not demonstrated that the existing ways in which the TDSIC mechanism addresses regulatory lag are insufficient, and has not shown any need to implement additional measures to reduce regulatory lag even further.

Q IN YOUR OPINION, IS IT GOOD RATEMAKING POLICY TO ADJUST RATES ON THE BASIS OF PROJECTED EXPENSES THAT THE UTILITY HAS NOT YET ACTUALLY INCURRED?

A No. Basing immediate rate increases on projections would introduce an unnecessary degree of speculation in the rate computation. When rates are set on the basis of actual costs that the utility is able to report it has actually incurred, there is a reliable level of certainty in the determination that is not present when rates are based on expectations and future intentions. As a matter of sound ratemaking policy, I recommend that the Commission reject NIPSCO's proposal to change its longstanding TDSIC practice in order to recover depreciation and property tax expenses on a projected basis.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

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Qualifications of Michael P. Gorman

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A In 1983 I received a Bachelor of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Master's Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission ("ICC"). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the Staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. ("DBA"). In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating to industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals ("RFPs") for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have participated in rate cases on rate design and class cost of service for electric, natural gas, water and wastewater utilities. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements, and have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the Federal Energy Regulatory Commission and numerous state regulatory commissions including: Alaska, Arkansas, Arizona, California, Colorado, Delaware, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Louisiana, Michigan, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, South Carolina, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory boards in Alberta and Nova Scotia, Canada. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the designation of Chartered Financial Analyst ("CFA") from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of the CFA Institute's Financial Analyst Society.

x

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**

Appendix B
Verified Direct Testimony and Attachments of

Michael P. Gorman

On behalf of

The NIPSCO Industrial Group

October 27, 2020

BRUBAKER & ASSOCIATES, INC.

Project 11043

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STATE OF INDIANA

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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**

<u>Appendix B Direct Testimony of Michael P. Gorman</u>

Q WHAT IS THE PURPOSE OF YOUR APPENDIX B?

A I will respond to the updated cost of common equity analysis sponsored by NIPSCO witness Vincent V. Rea. Mr. Rea recommends a return on equity of 10.7% for use in the TDSIC mechanism, which is the midpoint of his estimated range of 10.45% to 10.95%. The results reported by Mr. Rea are summarized in Table 6 below.[1]

[1]Rea Direct Testimony at 9.

TABLE 6

Mr. Rea's ROE Analysis

Model	Average (1)	Corrected (2)
DCF		
Analyst Growth	8.30% - 10.10%	8.90% - 9.20%
Retention Growth	7.3%	Reject
Hist. EPS Growth	9.50% - 10.20%	Reject
Unadjusted DCF Return	9.15% - 9.45%	8.90% - 9.20%
CAPM		
Unadjusted	10.42% - 10.51%	9.10% - 9.20%
Size Adjusted	11.52% - 11.24%	Reject
ECAPM	10.73% - 10.80%	Reject
Risk Premium		
Projected	10.06% - 10.17%	9.00% - 9.40%
Non-Utility Range	9.30% - 13.40%	Reject
Flotation Cost Adjustment	0.05%	Reject
Market-to-Book Adjustment	1.21%	Reject
Adjusted Range	**10.45% - 10.90%**	**8.9% - 9.4%**
Recommended ROE	**10.70%**	**9.4%**

Source: Rea Direct Testimony at 28-29, 32, 34.

As outlined above, Mr. Rea performed several versions of Discounted Cash Flow ("DCF") analysis using analysts' projected growth, retention growth methodology, and historical growth. He performed a traditional Capital Asset Pricing Model ("CAPM") and a CAPM analysis with a size adjustment. Mr. Rea also supplements his CAPM with an Empirical CAPM ("ECAPM"), which mitigates the expectation that high/low risk investments require greater/lower returns relative to the market return. Mr. Rea produces a risk premium analysis based on <u>projected</u> utility bond yields and an estimate of equity risk premiums.

Mr. Rea also includes an adder to his market-based measures of a fair return for NIPSCO by including a flotation cost adder and a market-to-book ratio adder. The combination of these two factors increases his estimated return by approximately 1.26 percentage points.

Q DOES MR. REA'S METHODOLOGY SUPPORT A 10.7% RETURN ON EQUITY FOR NIPSCO IN THIS MARKET?

A No. Mr. Rea's methodologies are either improperly constructed, based on flawed data, or reflect unjustified and inflated adders to the return on equity estimate. A more balanced and reasonable estimate of the current market cost of equity, as outlined in Column 2 of Table 6 above, shows that a fair return for NIPSCO in the current marketplace is in the range of 8.9% to 9.4%, or no higher than 9.4%.

<u>Return on Equity Adders</u>

Q DID MR. REA INCLUDE A FLOTATION COST ADJUSTMENT IN HIS RECOMMENDED RETURN FOR NIPSCO?

A Yes. Mr. Rea included an upward adjustment of 5 basis points to his return results to compensate for flotation costs. Mr. Rea developed his flotation cost adjustment by observing the cost NiSource (NIPSCO's parent company) incurred in issuing equity securities in the last 18 years. The costs incurred on the three historical issuances were in the range of 1.00% to 3.25% of the issuance amount. He also considered the future equity offerings publicly disclosed by NiSource. Mr. Rea states that these future offerings will incur flotation costs of approximately 1%. Based on the historical and future equity offerings, Mr. Rea determines a composite flotation cost rate of 1.25% is reasonable.

Next, Mr. Rea observes that of NIPSCO's common equity capital, approximately 43% is contributed, or paid-in capital from its parent company, while the other 57% of total common equity is attributed to undistributed retained earnings. To calculate the flotation cost adder, Mr. Rea then multiplies the 43% associated with paid-in capital by his composite flotation cost rate of 1.25%. The product is 0.538%, or 5 basis points.[2]

Q IS MR. REA'S FLOTATION COST ADDER REASONABLE?

A No. Mr. Rea's flotation cost adder is not reasonable or justified. Mr. Rea's flotation cost adder is not based on the recovery of prudent and verifiable actual flotation costs incurred by NIPSCO. As discussed in Schedule 9 of Mr. Rea's direct testimony, he derives a flotation cost adder based on the 43% of NIPSCO's common equity attributed to paid-in capital. While that capital may be "paid-in" by NiSource, it is not necessarily capital that incurred flotation costs. For example, NiSource receives dividend payments from its various subsidiaries and can do whatever it wants with that capital, like redistributing it to another subsidiary. Paid-in capital at NIPSCO can also be derived from debt capital issued at NiSource. Mr. Rea has failed to show that the entirety of NIPSCO's paid-in capital portion of its common equity balance derived from common equity issuances at NiSource.

Because he does not show that his adjustment is based on NIPSCO's actual and verifiable flotation expenses, there are no means of verifying whether Mr. Rea's proposal is reasonable or appropriate. Stated differently, Mr. Rea's flotation cost return on equity

[2] Rea Direct Testimony, Attachment 4-A, Schedule 9.

adder is not based on known and measurable NIPSCO costs. Therefore, the Commission should reject a flotation cost return on equity adder for NIPSCO.

Q PLEASE DESCRIBE MR. REA'S MARKET-TO-BOOK RATIO RETURN ON EQUITY ADDER.

A For his DCF analyses, the market-to-book ratio adder is based on the notion that the return on equity on a market value capital structure should be adjusted when applied to a book value capital structure. A market-to-book ratio adjustment is designed to maintain a targeted "market value" of the stock. Measuring a fair return, there is no justification in adjusting the return on book equity in order to maintain a target market-to-book ratio. The methodology simply does not represent an investment return that an investor would expect if they are making an investment in a security today. Therefore, the adjustment to the book return does not represent an appropriate risk-adjusted return in measuring NIPSCO's cost of equity.

Under Mr. Rea's DCF return, with a market-to-book ratio adder, he is finding that an investor could either purchase a utility stock with an investment risk similar to NIPSCO at a return of 9.50%, but in order to maintain the value of that stock, the utility should be allowed to earn a 10.71% return on incremental plant investment (DCF return plus market-to-book ratio adder). The result of this analysis would be to provide the utility an ability to earn a substantially in excess of market return on incremental plant investments. Such a methodology would create economic incentives for utilities to over-invest in utility plant equipment, which would have a detrimental impact on the utility's ability to offer just and reasonable prices to customers. Mr. Rea's proposal for an inflated return on plant investments is not appropriate, and is not consistent with the fair compensation standards outlined in *Hope* and *Bluefield*.[3]

Mr. Rea's DCF Analyses

Q PLEASE DESCRIBE MR. REA'S DCF ANALYSES.

A Mr. Rea applied several forms of the DCF model. He applied the traditional DCF model using three different growth rates: (1) a projected three- to five-year analyst earnings growth estimate; (2) a historical earnings growth rate; and (3) a retention growth rate.

For his gas LDC proxy group, the average "bare-bones" DCF results fall in the range of 7.30% to 10.20%. Based on this range, Mr. Rea determines an unadjusted DCF estimate of 9.45% to be appropriate.

Similarly, for his combination utility proxy group, the average DCF results fall in the range of 7.30% to 9.50%. Based on this range, Mr. Rea determines an unadjusted DCF estimate of 9.15% to be appropriate.

Mr. Rea then makes two adjustments to his unadjusted DCF result of 9.45% (gas) and 9.15% (combination). The first adjustment is the flotation cost adder of 5 basis points, which I described above. The second adjustment Mr. Rea makes is a market-to-book adjustment of 1.21%, or 121 basis points. These two adders increase his DCF estimate of 9.45% to 10.71% for the gas group and from 9.15% to 10.41% for the combination group.

[3] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*") and *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923) ("*Bluefield*").

Q DID MR. REA MAKE ANY ADJUSTMENTS TO HIS PROXY GROUP RESULTS IN FORMING HIS RECOMMENDED DCF RETURN?

A Yes. In developing his recommended DCF range, Mr. Rea excluded what he found to be "outlier" results. Mr. Rea used a form of the Federal Energy Regulatory Commission's ("FERC") low-end outlier test to determine outlier DCF results. As a result of this methodology, Mr. Rea removed six low-end and high-end outliers from his utility proxy groups and seven outliers from his non-regulated utility group DCF study.[4]

Q WHAT ISSUES DO YOU HAVE WITH MR. REA'S DCF ANALYSIS?

A I have several issues with Mr. Rea's DCF analysis. However, to limit issues in this case, I will only comment on the following: (1) his flotation cost adder; (2) his application of a market-to-book ratio adjustment, or financial risk adder; and (3) Mr. Rea's use of the FERC low-end and high-end outlier threshold. For the reasons discussed above, Mr. Rea's flotation cost adder and market-to-book adjustment are not reasonable and should be rejected. I will not repeat those arguments here.

Q HOW DID MR. REA IMPLEMENT AN OUTLIER TEST IN INTERPRETING THE RESULTS OF HIS PROXY GROUP DCF ANALYSES?

A In his Schedule 2, Mr. Rea outlines how he applied the FERC "low-end" outlier threshold. Mr. Rea used a risk premium factor of 1.77% to apply to his most recent Baa/BBB utility yield of 4.15% to obtain his low-end outlier threshold of 5.91%. He developed the risk premium factor of 1.77% by applying 20% weighted factor per FERC Option 569 to his

[4]Schedule 2-4.

market risk premium used in his CAPM analysis. Therefore, Mr. Rea excludes all cost of equity estimates that fall below 5.91% from his analysis.

He also excludes some costs estimates because they are 150% above the average DCF result prior to eliminating any estimates.

Q IS MR. REA'S APPLICATION OF AN OUTLIER TEST REASONABLE?

A No. Mr. Rea's subjective elimination of certain proxy group companies prevents him from determining the central tendency of the proxy group results. This is significant because it is the proxy group as a whole that is measured to be reasonably comparable in investment risk to NIPSCO. Excluding outliers as Mr. Rea has done distorts the risk characteristics of the proxy group, and does not produce a return that reasonably reflects fair compensation for the investment risk of the proxy group.

Q HOW SHOULD THE CENTRAL TENDENCY OF THE PROXY GROUP BE MEASURED, WITH THE POTENTIAL SKEWING EFFECTS CREATED BY OUTLIERS WITHIN THE GROUP?

A Excluding individual proxy group companies' estimates from the proxy group does not result in an accurate interpretation of the central tendency of the proxy group results. I recommend the Commission consider use of the proxy group median, as opposed to the average results, in interpreting the proxy group results. To the extent there is a significant discrepancy between the proxy group average and the proxy group median, this would be an indication that outliers are having a significant impact on the proxy group results. Under these circumstances, the Commission should give primary weight to the proxy group median results, and little weight to the proxy group average results.

Q ARE THERE ANY OTHER ISSUES WITH MR. REA'S DCF ANALYSES?

A Yes. I recommend the Commission give no weight to the DCF studies based on historical growth rates. Historical growth rates simply are not a good proxy for expectations of future growth. If the growth rate does not align with investor's outlooks in valuing a utility stock, then you will not get an accurate measurement of the investor-required return. Investors buy stock for prospective earnings, not historical earnings.

Second, I recommend providing little weight to the DCF analysis based on retention growth rates simply because of the results in this proceeding. A DCF return of 7.30% is, in my judgement, unreasonably low and should be given little consideration.

Q WHAT WOULD BE MR. REA'S DCF RETURN ESTIMATE IF THE ISSUES DISCUSSED ABOVE ARE CORRECTED?

A Excluding Mr. Rea's adders for market-to-book, flotation cost adjustment, Mr. Rea's proxy group median results for his consensus analysts' growth rate estimates indicate a DCF return within the range of 8.90% to 9.20%, as shown on my Attachment MPG-5.

CAPM Studies

Q PLEASE DESCRIBE MR. REA'S TRADITIONAL CAPM ANALYSIS.

A Mr. Rea developed a traditional CAPM analysis relying on the average of a projected and historical market risk premium. His S&P projected DCF-derived market return of 11.47% is based on a 1.84% dividend yield and a projected growth rate of 10.28%. His *Value Line* prospective market return of 15.63% is based on a dividend yield of 2.43% and a growth rate of 13.20%. Mr. Rea uses the average of these two prospective market return estimates of 13.55% and a projected 30-year Treasury bond yield of 2.62% to derive his prospective market risk premium of 10.93%.

Mr. Rea calculated his historical market risk premium of 7.20% by subtracting the historical Treasury bond income return of 4.90% from the historical average total market return of 12.10%.

Mr. Rea develops the market risk premium of 9.07% used in his CAPM analysis by averaging his prospective market risk premium of 10.93% and his historical market risk premium of 7.20%.

Mr. Rea relies on the projected 30-year Treasury yield of 2.62%, his market risk premium of 9.07% as described above and a beta coefficient of 0.86 (gas) and 0.87 (combination) to produce unadjusted CAPM return estimates of 10.42% and 10.51%, respectively.

Finally, Mr. Rea adds a 0.05% premium for flotation costs and a size adjustment premium of 1.10% (gas) and a 0.73% (combination) to his CAPM return estimate to arrive at his cost of equity of 11.57% (gas) and 11.29% (combination).[5]

Q ARE MR. REA'S TRADITIONAL CAPM ANALYSES REASONABLE?

A No. There are several flaws with Mr. Rea's analyses. Specifically, with regard to his traditional CAPM analysis, his projected risk-free rate of 2.62% reflects the period 2021-2025 period, and the size premium added to his CAPM estimate is not based on firms of comparable risk to NIPSCO. As discussed above, Mr. Rea application of the flotation cost adjustment is not reasonable and should be rejected. While I disagree with the derivation

[5] Rea Direct Testimony at 32 and Schedule 5.

of his DCF-based market risk premium of 9.07%, to limit the issues with Mr. Rea's testimony, I will focus my rebuttal on his size adjustment and his use of projected yields.

Q PLEASE DESCRIBE MR. REA'S SIZE ADJUSTMENT?

A Mr. Rea's size adjustment return on equity adder is based on estimates made by Duff & Phelps' *Cost of Capital Navigator*. Duff & Phelps estimates various size adjustments based on differentials in beta estimates tied to the size of a company. Mr. Rea does not provide a detailed discussion on the application of the size adjustment, except that the capitalization for companies included in his gas proxy group fall in Duff & Phelps 5th Decile, which warrants a size adjustment of a 110 basis points. Similarly, on Schedule 5 of his direct testimony he notes that the capitalization of the companies included in his combination proxy group fall in the 3rd Decile.

Q WHY DO YOU FIND MR. REA'S SIZE ADJUSTMENT INAPPROPRIATE?

A There are several problems with this size adjustment. First, Mr. Rea applied a size adjustment without even considering the average capitalization of his proxy groups relative to the capitalization of NiSource, NIPSCO's parent to determine, whether a size adjustment is even appropriate. A return on equity adder is not justified in the way performed by Mr. Rea. Specifically, NiSource has a market capitalization of $9.2 billion, which puts it in the 3rd Decile, which is comparable to the capitalization of the combination group as disclosed in the footnotes of Schedule 5, Page 4. Therefore, the size adjustment is not warranted for the combination proxy group. Similarly, the gas companies fall in the 5th decile, which equates to a market capitalization in the range of $2.7 to $4.3 billion, which is about half of the capitalization of NiSource. Therefore, if any size adjustment is applied it should be negative and it will reduce the return on equity produced by Mr. Rea's CAPM analysis.

Stated very simplistically, the holding company which owns NIPSCO has a market capitalization that is *greater* than or comparable to that of the proxy group company average market capitalization. NIPSCO gets its equity from equity infusions from its parent company and earnings it retains from operations. NIPSCO does not sell stock to the market. For this reason, the market capitalization of its parent company is what is relevant in assessing NIPSCO's market capitalization risk.

Third, and probably most significantly, NIPSCO receives all of his external capital through NiSource Finance Corp., which is a wholly owned subsidiary of NiSource and engages in financing activities to raise funds for the business operations of NiSource and its subsidiaries. The majority of all debt issues are based on intercompany notes from NiSource Finance Corp.

Most importantly, customers pay for the risk mitigation for NIPSCO by paying rates that recover NIPSCO's service company fees and charges from NiSource Finance Corp.. Mr. Rea's proposal for a return on equity premium ignores this service company relationship, and the costs incurred by retail customers of NIPSCO for the costs and benefits of this holding company structure. The holding company structure is designed to mitigate operating affiliates' stand-alone investment risk. For these reasons, Mr. Rea's proposed small company risk adder to the return on equity should be rejected.

Finally, the size adjustment, as applied by Mr. Rea, is not risk comparable for NIPSCO.

Q WHY IS MR. REA'S SIZE ADJUSTMENT NOT RISK COMPARABLE TO NIPSCO?

A His size adjustment is based on companies that have significantly more systematic risks that are not reflective of the utility industry or NIPSCO. The size adjustments relied on by Mr. Rea reflects companies that have unadjusted beta estimates well in excess of 1.00.[6] I have provided the beta estimates, as calculated by Duff & Phelps for each decile below in Table 7.

TABLE 7

Duff & Phelps Size Adjustments and Corresponding Betas

CRSP Decile	**Market Cap ($ Bill)**	**Size Premium**	**Beta D&P OLS**	**Beta VL Proxy**	**Beta OLS Proxy***
1	$ 31,090.379	-0.27%	0.92	0.87	0.78
2	$ 13,142.606	0.48%	1.04	0.87	0.78
3	$ 6,618.604	0.69%	1.11	0.87	0.78
4	$ 4,312.546	0.77%	1.13	0.87	0.78
5	$ 2,688.889	1.08%	1.17	0.87	0.78
6	$ 1,669.856	1.37%	1.17	0.87	0.78
7	$ 993.855	1.47%	1.25	0.87	0.78
8	$ 515.621	1.61%	1.30	0.87	0.78
9	$ 230.024	2.26%	1.33	0.87	0.78
10	$ 1.973	4.99%	1.39	0.87	0.78

Source:
Duff & Phelps Cost of Capital Navigator, 2020 Cost of Capital: Annual U.S. Guidance and Examples, (Chapter 7, pp. 10, and CRSP Deciles Size Study).
* Raw Beta = (VL Beta - 0.35) / 0.67.

These unadjusted beta estimates are substantially higher than the average adjusted Value Line beta of 0.86 (gas) and 0.87 (combination) used by Mr. Rea as reflective of the Company's investment risk. To put this into a more of an apple-to-apples comparison, I have also provided the average unadjusted Ordinary Least Squares ("OLS")

[6] *Duff & Phelps Cost of Capital Navigator 2020, CRSP Deciles Size Study*.

beta for Mr. Rea's proxy group (0.78). As shown above, every decile measured by Duff & Phelps has a much higher beta than Mr. Rea's utility groups. The typical company in each decile is much riskier than the typical utility company. Because of this significant disparity in risk, as measured by beta, Mr. Rea's size adjustment produces a CAPM return estimate that does not produce a risk appropriate return for NIPSCO and therefore, should be rejected.

Q CAN YOU EXPLAIN HOW BETA CORRESPONDS WITH THE LEVEL OF INVESTMENT RISK FOR A COMPANY AND THEREFORE PRODUCES AN APPROPRIATE RISK-ADJUSTED RETURN FOR A SUBJECT COMPANY?

A Yes. Beta represents a measure of systematic or non-diversifiable, market-related risk. All subject Company's betas are measured relative to that of the overall market and adjusted upward by *Value Line*. The market beta is considered to be 1.0. For companies that have betas greater than 1, they are regarded as having more risk than the overall market. For companies that have betas less than 1, they are regarded to have risk less than the overall market.

For these reasons, utility companies which consistently and predictably have adjusted betas far less than 1 (usually in the range of 0.6 to 0.8 depending on market conditions) are generally reflective of lower risk investment options. I would also point out that the current beta estimates for Mr. Rea's proxy group are significantly higher relative to historical estimates as shown on my Attachment MPG-6.

Q WHY DO YOU FIND MR. REA'S PROJECTED RISK FREE RATE OF 2.62% UNREASONABLE?

A Mr. Rea's use of a long-term projected bond yield of 2.62%[7] is expected to be in effect in up to five years out (period 2021-2025). This risk-free rate is limited to market participants' outlooks for NIPSCO's cost of capital during the period rates determined in this proceeding will be in effect. This bond yield is largely based on projections of Treasury bond yields five years out. Those projections are highly uncertain, and in any event do not reflect the cost of capital currently or even the period over the next two to three years, the period in which rates determined in this proceeding will largely be in effect. As such, the CAPM and risk premium methodology should be based on observable bond yields in the market today. The most recent *Blue Chip Financial Forecasts* shows a 30-year Treasury bond yield of 1.9% for the first quarter of 2022, which reflects a reasonable near-term risk-free expectation.[8]

Q DO YOU HAVE ANY ADDITIONAL COMMENTS IN REGARD TO MR. REA'S CAPM MODEL?

A Yes. In his direct testimony Mr. Rea relied an additional market return of 15.63% based on *Value Line* as described above. Even though Mr. Rea testifies to have updated his study from NIPSCO's last gas rate case, I reviewed Mr. Rea's testimony in NIPSCO's last gas (Cause No. 44988) and it appears that Mr. Rea did not rely on the *Value Line* market return, which is based on a growth rate estimate of 13.20% and a dividend yield of 2.43%. The *Value Line* market growth rate estimate is excessive and inflates the market return estimate. Indeed, it is more than 3 times higher than the long-term growth rate of the

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[7]Rea Direct Testimony, Attachment 4-A, Schedule 5.
[8]*Blue Chip Financial Forecasts*, October 1, 2020 at 2.

economy of 4.2% as measured by the projected GDP growth over the next five-to-ten years as published by the *Blue Chip Economic Indicators*.[9]

Therefore, relying on Mr. Rea's S&P DCF-derived market return of 11.47% and the near-term projected risk-free rate of 1.9% will produce a perspective market risk premium of 9.57%. Hence, Mr. Rea's market risk premium applied in his CAPM analysis will be 8.39%, which is the average of his perspective market risk premium of 9.57% and his historical market risk premium 7.20%.

Q CAN MR. REA'S CAPM ANALYSIS BE REVISED TO REFLECT THE REMOVAL OF THE SIZE ADJUSTMENT AND RECENT RISK-FREE RATES?

A Yes. Disregarding Mr. Rea's size adjustment, using the most recent projection for the near-term risk-free rate of 1.9%, a market risk premium of 8.39%, and his beta estimates of 0.86% (gas) and 0.87% (combination), produce a CAPM return of 9.1% (gas) and 9.2% (combination).[10]

<u>ECAPM</u>

Q DID MR. REA ALSO PERFORM AN EMPIRICAL CAPM ("ECAPM") ANALYSIS?

A Yes. Mr. Rea performed an ECAPM analysis that relied on the same market risk premium of 9.07%, the same projected risk-free rate of 2.62%, and the same average *Value Line* betas that he used in his traditional CAPM analyses.

He then uses an ECAPM model that applies a 25% weighting factor to the market beta of 1, and a 75% weighting factor to the utility beta. This produces an ECAPM estimates of 10.73% (gas) and 10.85% (combinations).

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[9] *Blue Chip Economic Indicators*, October 10, 2020 at 14.
[10] 1.9% + 0.86 x 8.39% = 9.1% (gas), 1.9% + 0.87 x 8.39% = 9.2% (combination).

Q ARE MR. REA'S ECAPM ANALYSES REASONABLE?

A No. Mr. Rea's ECAPM analyses share some of the same flaws as his traditional CAPM analyses. Mr. Rea's proposal to adjust the ECAPM result upward applying a flotation cost adjustment and his reliance on projected risk-free rate that is 5 years out into the future is inappropriate and should be rejected for the same reasons discussed in response to his traditional CAPM.

Q DO YOU HAVE ANY OTHER ISSUES WITH MR. REA'S ECAPM ANALYSES?

A Yes. Mr. Rea's ECAPM analysis is flawed because his model was developed using adjusted utility betas. The impact of Mr. Rea's ECAPM adjustments increases his *Value Line* adjusted beta estimate of approximately 0.87 to 0.90.[11] The weighting adjustments applied in the ECAPM are mathematically the same as adjusting beta since the inputs are all multiplicative as shown in the formula above.

Further, Mr. Rea's reliance on an adjusted *Value Line* beta in his ECAPM study is inconsistent with the academic research that I am aware of supporting the development of the ECAPM.[12] The end result of using adjusted betas in the ECAPM is essentially an expected return line that has been flattened by two adjustments. In other words, the vertical intercept has been raised twice and the security market line has been flattened twice: once through the adjustments *Value Line* made to the raw beta, and again by weighting the risk-adjusted market risk premium as Mr. Rea has done. In addition to the many adjustments employed by Mr. Rea, he further increases the intercept and flattens the security market line by using projected long-term Treasury yields that are at odds with

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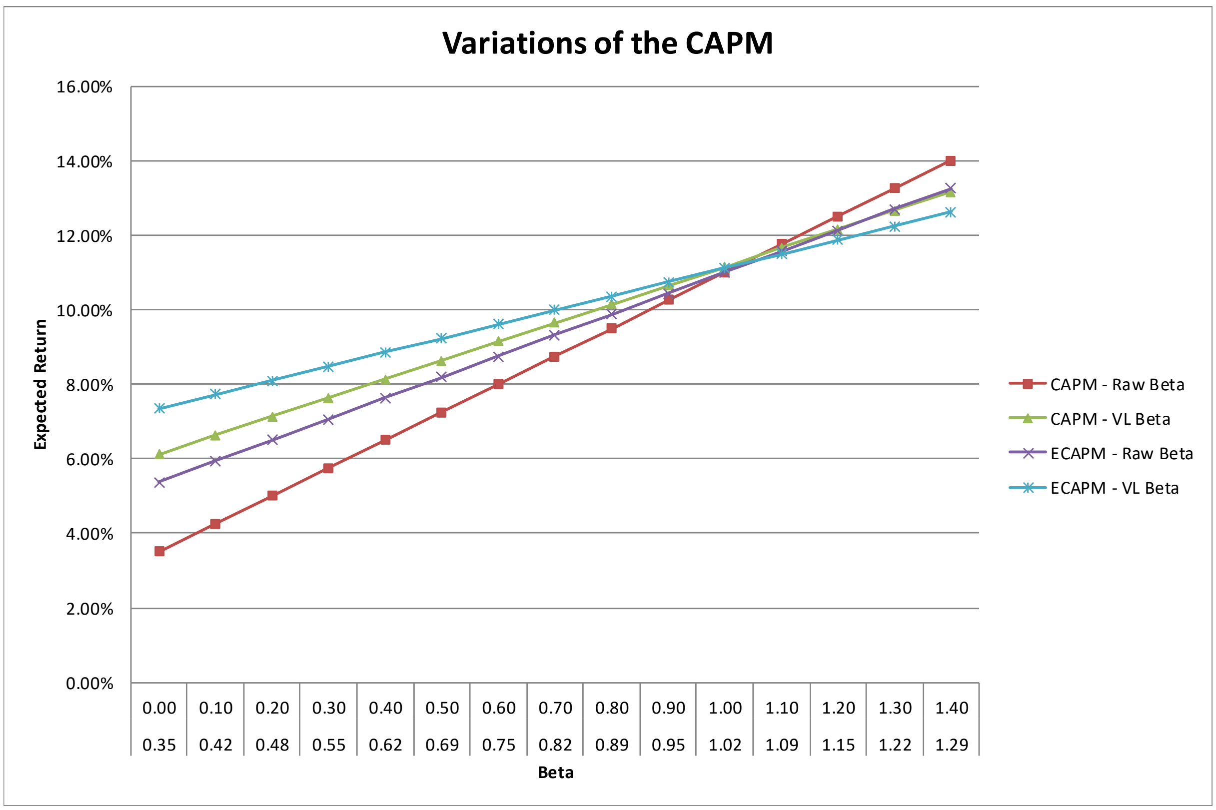
[11] 75% x 0.87 + 25% x 1 = 0.90.

[12] See Black, Fischer, "Beta and Return," *The Journal of Portfolio Management,* Fall 1993, 8-18; and Black, Fischer, Michael C. Jensen and Myron Scholes, "The Capital Asset Pricing Model: Some Empirical Tests," 1972.

current market expectations and inconsistent with the Federal Reserve's projections and monetary policy.

The ECAPM technically will raise the intercept point of the security market line and flatten the slope. Again, this has the effect of increasing CAPM return estimates for companies with betas less than 1, and decreasing the CAPM return estimates for companies with betas greater than 1. I have modeled the expected return line resulting from the application of the various forms of the CAPM/ECAPM below in Figure 5.

FIGURE 5



Along the horizontal axis in Figure 5 above, I have provided the raw unadjusted beta (top row) and the corresponding adjusted *Value Line* beta (bottom row). *As* shown in Figure 5 above, the CAPM using a *Value Line* beta compared to the CAPM using an unadjusted beta shows that the *Value Line* beta raises the intercept point and flattens the slope of the security market line. As shown in the figure above, the two variations with the most similar slope are the CAPM with the *Value Line* beta, and the ECAPM with a raw beta. This evidence shows that the ECAPM adjustment has a very similar impact on the expected return line as a *Value Line* beta. Another observation that can be made from the figure above is the magnifying effect that the ECAPM using a *Value Line* beta has on raising the vertical intercept and flattening the slope relative to all other variations. There is simply no legitimate basis to use an adjusted beta within an ECAPM because it unjustifiably alters the security market line and materially inflates a CAPM return for a company with a beta less than 1.

Q IN YOUR EXPERIENCE, IS MR. REA'S PROPOSED USE OF AN ADJUSTED BETA IN AN ECAPM STUDY WIDELY ACCEPTED IN THE REGULATORY ARENA?

A No. In my experience, regulatory commissions generally disregard the use of the ECAPM, particularly when an adjusted beta is used in the model.

Q IS THERE A WAY TO MORE ACCURATELY MEASURE THE COST OF EQUITY FOR NIPSCO USING THE ECAPM?

A Because the ECAPM model is based on an unadjusted regression beta, if the appropriate beta is used in the ECAPM it would produce a reasonable return estimate. This can be accomplished by removing, or backing out, the adjustment from *Value Line*'s published beta.

Removing *Value Line*'s beta adjustment will produce the original regression beta estimate. Using this regression beta in the ECAPM will produce a more accurate result than that offered by Mr. Rea. As explained earlier, Mr. Rea's proxy groups have an average *Value Line* beta of 0.86 (gas) and 0.87 (combination). By removing the adjustments that Value Line made to produce the proxy group's average beta of approximately 0.87, I have calculated the original regression beta of 0.78.[13] Using the regression beta of 0.78 in the ECAPM model will produce an expected return estimate of approximately 8.9%.[14]

Risk Premium

Q PLEASE DESCRIBE MR. REA'S RISK PREMIUM ANALYSIS.

A Mr. Rea's Risk Premium Method analysis is developed on his Schedule 6. Throughout that exhibit he develops several equity risk premium estimates based on the total market index approach and the public utility index approach.

Mr. Rea developed his own forecasted bond yield of 4.14% (gas) and 4.21% (combination). He calculated this prospective bond yield by starting with the forecasted "Aaa" rated corporate bond yield of 3.56% for the 2021-2025 period. To this he adds a 0.45% yield spread to account for the historical spread between "A" rated utility bond yields and Aaa-rated corporate bond yields. Finally, he calculates an interpolated yield spread between A-rated utility bond yields and Baa-rated bond yields to account for his gas LDC Group's A-/A3 ratings and A-/Baa1 ratings of his combination group's. The interpolated yield spreads are 0.13% (gas) and 0.20% (combination). Collectively, Mr. Rea calculates a prospective bond yield of 4.14% (gas) and 4.21% (combination)

To calculate his total market index equity risk premium, Mr. Rea measured the historical realized equity risk premium between the total return on the market of 12.10% and the total return for long-term corporate bonds of 6.40%. This produces an equity risk

[13]Raw Beta = (VL Beta - 0.35) / 0.67, Raw Beta = (0.87%-0.35%) / 0.67 = 0.78
[14]ECAPM = RF + 0.25 x MRP + 0.75 x MRP x Unadjusted Beta. ECAPM = 1.9% + 0.25 x 8.39% + 0.75 x 8.39% x 0.78 = 8.9%.

premium of 5.70%. Next, Mr. Rea calculated a prospective equity risk premium by subtracting the forecasted Aaa-rated corporate bond yield of 3.56% as described above from his prospective total market return of 13.55% that was used in his CAPM analysis. This produced a total market index equity risk premium of 9.99%. The average of his two total market risk premiums is 7.85% ((5.70% + 9.99%) / 2). Mr. Rea then adjusted this total index risk premium by his beta estimate of 0.86 (gas) and 0.87 (combination) to produce a utility equity risk premium of 6.75% (gas) and 6.83% (combination).

Next, Mr. Rea calculates a public utility index equity risk premium. He does this by measuring the historical utility index equity risk premium of the S&P 500 Utilities index (10.94%) over the Moody's A-rated utility bond yield average (6.32%). This produces a historical equity risk premium of 4.63%.

Next, Mr. Rea subtracts his most recent 2-month average Moody's "A" rated utility yield of 3.11% from his DCF Market return on the S&P Utility Index of 8.67% to produce an implied equity risk premium of 5.57%. The average of his public utility index equity risk premiums is 5.10% (average of 4.63% and 5.57%).

Mr. Rea then adds his prospective bond yield of 4.14% (gas) and 4.21% (combination) to his average equity risk premium estimate of 5.91% (gas) and 5.96% (combination)) to produce his risk premium return estimate of 10.06% (gas) and 10.17% (combination). Once, again, Mr. Rea then adds a 0.05% premium to compensate for flotation costs.

Q WHAT CONCERNS DO YOU HAVE WITH MR. REA'S RISK PREMIUM METHOD?

A My major concern with Mr. Rea's Risk Premium Method is his overstated prospective utility bond yield, which does not reflect the current market outlooks.

Q WHY DO YOU BELIEVE THAT MR. REA'S PROJECTED UTILITY YIELD OF 4.14% (GAS) AND 4.21% (COMBINATION) DO NOT REFLECT CURRENT MARKET OUTLOOKS?

A Mr. Rea uses a projected Aaa-rated corporate bond yield of 3.56% for the period 2021 through 2025. He then adds two separate yield spreads to produce his prospective bond yield for his proxy group. As shown on page 3 of Schedule 6 the most recent A-and Baa-rated utility bond yields as of June 2020 are approximately 3.07% and 3.44%, respectively. Mr. Rea's projected increase to A-rated and Baa-rated utility bond yields does not reflect the current market outlooks.

Q CAN MR. REA'S RISK PREMIUM ANALYSES BASED ON PROJECTED YIELDS BE MODIFIED TO PRODUCE MORE REASONABLE RESULTS?

A Yes. Relying on Mr. Rea's equity risk premium of 5.92% (gas) and the current A-rated utility yield of 3.07%, will result in a risk premium return on equity of approximately 8.99% (3.07% + 5.92%), rounded to 9.0% for his gas proxy group. Using current observable Baa-rated bond yields of 3.44% and his combination equity risk premium of 5.96% would imply a common equity return of 9.4% (3.44% + 5.96%). Therefore Mr. Rea's risk premium return estimate will fall in the range 9.0% to 9.4%. I believe this return more reasonably captures a fair equity risk premium estimate using the data in Mr. Rea's study.

<u>Non-Utility Proxy Group</u>

Q DID MR. REA USE A NON-UTILITY PROXY GROUP IN SUPPORT OF HIS RECOMMENDED 10.7% RETURN FOR NIPSCO?

A Yes. Mr. Rea performed his DCF, CAPM, and ECAPM on a non-utility proxy group, which he found to be a reasonable risk proxy for NIPSCO.

Q IS MR. REA'S NON-UTILITY GROUP PRODUCING REASONABLE RETURN ESTIMATES FOR NIPSCO?

A No. The companies included in Mr. Rea's non-utility proxy group are subject to risks that are different from those affecting NIPSCO's regulated utility operations. As noted by the major credit rating agencies, the utility industry has relatively low risk in comparison with the market. Indeed, the regulatory process itself provides an effective mechanism to mitigate some of the market risks influencing the U.S. economy. Therefore, using Mr. Rea's non-utility proxy group, which is much riskier than the utility industry, will produce an unreliable and inflated return on equity for a low-risk utility like NIPSCO. Therefore, the Commission should disregard the results of Mr. Rea's non-utility group DCF.

Q PLEASE EXPLAIN WHY MR. REA'S NON-UTILITY GROUP IS NOT A REASONABLE RISK PROXY GROUP FOR NIPSCO.

A One criterion that Mr. Rea uses to select a comparable risk non-utility group in order to estimate NIPSCO's return on equity, is the bond rating. While this is a somewhat reasonable method of estimating and identifying comparable proxy groups within the industry, doing it across industries is not as straightforward and not as reliable. For example, if bond ratings alone would adequately help to identify comparable risk companies across industries, then there should not be any observable clear differences in the investment cost for securities that had different bond ratings. However, the industry or circumstances behind the security have a material role in the market's assessment of a fair compensation.

While "AAA" rated corporate bonds and U.S. Treasuries have comparable bond ratings, the risk differential is significant largely because of the operating risk differences between the securities. The U.S. government has virtually minimal default risk on its bond issuances, whereas even a "AAA" rated corporate bond has measurable default risk. Similarly, regulated utility operations and the ability to adjust prices to cost of service provide far less default risk than that of non-regulated companies. A regulated company generally has a franchise to a monopolistic service territory, the ability to set prices based on reasonable and prudent costs, and minimal competition. In significant contrast, a non-regulated entity does not have a franchised or monopolistic customer base, must price its services consistent with what the market will permit, and has far more uncertainty of selling products that produce cash flows that support financial obligations. Therefore, the DCF results produced by Mr. Rea's non-utility group should be rejected.

Q WHAT IS YOUR CONCLUSION REGARDING THE APPROPRIATE RETURN ON EQUITY FOR NIPSCO BASED ON YOUR ANALYSIS?

A My analysis supports a reasonable range of NIPSCO's current market cost of equity to be from 8.90% to 9.40%, or no more than 9.40%.

The Commission should reject Mr. Rea's recommended cost of common equity for the reasons outlined above, primarily because his analysis has artificially inflated NIPSCO's cost of equity through unreasonable adjustments.

Q DOES THIS CONCLUDE YOUR APPENDIX B DIRECT TESTIMONY?

A Yes, it does.

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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**

Verification

I, Michael P. Gorman, a Managing Principal of Brubaker & Associates, Inc., affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

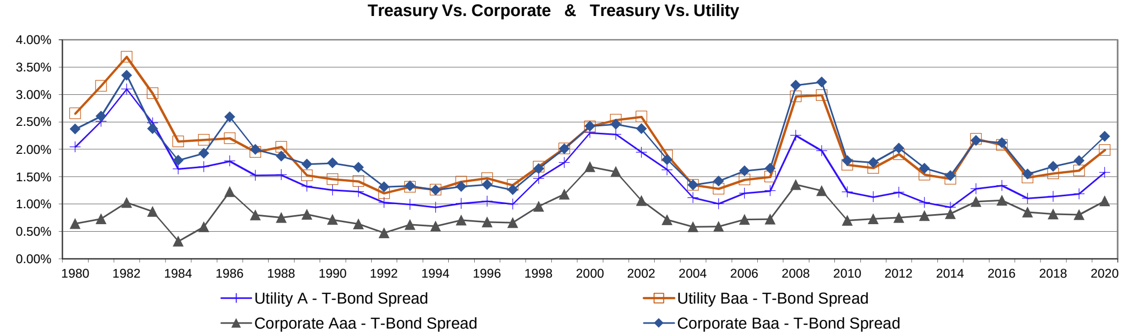
Michael P. Gorman
October 27, 2020

Northern Indiana Public Service Company

Bond Yield Spreads

Line	Year	T-Bond Yield[1] (1)	Public Utility Bond A[2] (2)	Baa[2] (3)	A-T-Bond Spread (4)	Baa-T-Bond Spread (5)	Corporate Bond Aaa[3] (6)	Baa[3] (7)	Aaa-T-Bond Spread (8)	Baa-T-Bond Spread (9)	Utility to Corporate Baa Spread (10)	A-Aaa Spread (11)
1	1980	11.30%	13.34%	13.95%	2.04%	2.65%	11.94%	13.67%	0.64%	2.37%	0.28%	1.40%
2	1981	13.44%	15.95%	16.60%	2.51%	3.16%	14.17%	16.04%	0.73%	2.60%	0.56%	1.78%
3	1982	12.76%	15.86%	16.45%	3.10%	3.69%	13.79%	16.11%	1.03%	3.35%	0.34%	2.07%
4	1983	11.18%	13.66%	14.20%	2.48%	3.02%	12.04%	13.55%	0.86%	2.38%	0.65%	1.62%
5	1984	12.39%	14.03%	14.53%	1.64%	2.14%	12.71%	14.19%	0.32%	1.80%	0.34%	1.32%
6	1985	10.79%	12.47%	12.96%	1.68%	2.17%	11.37%	12.72%	0.58%	1.93%	0.24%	1.10%
7	1986	7.80%	9.58%	10.00%	1.78%	2.20%	9.02%	10.39%	1.22%	2.59%	-0.39%	0.56%
8	1987	8.58%	10.10%	10.53%	1.52%	1.95%	9.38%	10.58%	0.80%	2.00%	-0.05%	0.72%
9	1988	8.96%	10.49%	11.00%	1.53%	2.04%	9.71%	10.83%	0.75%	1.87%	0.17%	0.78%
10	1989	8.45%	9.77%	9.97%	1.32%	1.52%	9.26%	10.18%	0.81%	1.73%	-0.21%	0.51%
11	1990	8.61%	9.86%	10.06%	1.25%	1.45%	9.32%	10.36%	0.71%	1.75%	-0.30%	0.54%
12	1991	8.14%	9.36%	9.55%	1.22%	1.41%	8.77%	9.80%	0.63%	1.67%	-0.25%	0.59%
13	1992	7.67%	8.69%	8.86%	1.02%	1.19%	8.14%	8.98%	0.47%	1.31%	-0.12%	0.55%
14	1993	6.60%	7.59%	7.91%	0.99%	1.31%	7.22%	7.93%	0.62%	1.33%	-0.02%	0.37%
15	1994	7.37%	8.31%	8.63%	0.94%	1.26%	7.96%	8.62%	0.59%	1.25%	0.01%	0.35%
16	1995	6.88%	7.89%	8.29%	1.01%	1.41%	7.59%	8.20%	0.71%	1.32%	0.09%	0.30%
17	1996	6.70%	7.75%	8.17%	1.05%	1.47%	7.37%	8.05%	0.67%	1.35%	0.12%	0.38%
18	1997	6.61%	7.60%	7.95%	0.99%	1.34%	7.26%	7.86%	0.66%	1.26%	0.09%	0.34%
19	1998	5.58%	7.04%	7.26%	1.46%	1.68%	6.53%	7.22%	0.95%	1.64%	0.04%	0.51%
20	1999	5.87%	7.62%	7.88%	1.75%	2.01%	7.04%	7.87%	1.18%	2.01%	0.01%	0.58%
21	2000	5.94%	8.24%	8.36%	2.30%	2.42%	7.62%	8.36%	1.68%	2.42%	-0.01%	0.62%
22	2001	5.49%	7.76%	8.03%	2.27%	2.54%	7.08%	7.95%	1.59%	2.45%	0.08%	0.68%
23	2002	5.43%	7.37%	8.02%	1.94%	2.59%	6.49%	7.80%	1.06%	2.37%	0.22%	0.88%
24	2003	4.96%	6.58%	6.84%	1.62%	1.89%	5.67%	6.77%	0.71%	1.81%	0.08%	0.91%
25	2004	5.05%	6.16%	6.40%	1.11%	1.35%	5.63%	6.39%	0.58%	1.35%	0.00%	0.53%
26	2005	4.65%	5.65%	5.93%	1.00%	1.28%	5.24%	6.06%	0.59%	1.42%	-0.14%	0.41%
27	2006	4.87%	6.07%	6.32%	1.20%	1.44%	5.59%	6.48%	0.71%	1.61%	-0.16%	0.48%
28	2007	4.83%	6.07%	6.33%	1.24%	1.50%	5.56%	6.48%	0.72%	1.65%	-0.15%	0.52%
29	2008	4.28%	6.53%	7.25%	2.25%	2.97%	5.63%	7.45%	1.35%	3.17%	-0.20%	0.90%
30	2009	4.07%	6.04%	7.06%	1.97%	2.99%	5.31%	7.30%	1.24%	3.23%	-0.24%	0.73%
31	2010	4.25%	5.47%	5.96%	1.22%	1.71%	4.95%	6.04%	0.70%	1.79%	-0.08%	0.52%
32	2011	3.91%	5.04%	5.57%	1.13%	1.66%	4.64%	5.67%	0.73%	1.76%	-0.10%	0.40%
33	2012	2.92%	4.13%	4.83%	1.21%	1.90%	3.67%	4.94%	0.75%	2.02%	-0.11%	0.46%
34	2013	3.45%	4.48%	4.98%	1.03%	1.53%	4.24%	5.10%	0.79%	1.65%	-0.12%	0.24%
35	2014	3.34%	4.28%	4.80%	0.94%	1.46%	4.16%	4.86%	0.82%	1.52%	-0.06%	0.12%
36	2015	2.84%	4.12%	5.03%	1.27%	2.19%	3.89%	5.00%	1.05%	2.16%	0.03%	0.23%
37	2016	2.60%	3.93%	4.67%	1.33%	2.08%	3.66%	4.71%	1.07%	2.12%	-0.04%	0.27%
38	2017	2.90%	4.00%	4.38%	1.10%	1.48%	3.74%	4.44%	0.85%	1.55%	-0.06%	0.26%
39	2018	3.11%	4.25%	4.67%	1.14%	1.56%	3.93%	4.80%	0.82%	1.69%	-0.13%	0.32%
40	2019	2.58%	3.77%	4.19%	1.18%	1.61%	3.39%	4.38%	0.81%	1.79%	-0.18%	0.38%
41	2020 [4]	1.54%	3.12%	3.52%	1.57%	1.98%	2.60%	3.78%	1.06%	2.24%	-0.25%	0.52%
42	**Average**	**6.31%**	**7.81%**	**8.24%**	**1.50%**	**1.93%**	**7.15%**	**8.24%**	**0.84%**	**1.93%**	**0.00%**	**0.65%**

Yield Spreads
Treasury Vs. Corporate & Treasury Vs. Utility



Sources:
[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
[2] The utility yields for the period 1980-2000 were obtained from Mergent Public Utility Manual, Mergent Weekly News Reports, 2003.
The utility yields for the period 2001-2009 were obtained from the Mergent Bond Record.
The utility yields for the period 2010-2019 were obtained from http://credittrends.moodys.com/.
[3] The corporate yields for the period 1980-2009 were obtained from the St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
The corporate yields from 2010-2019 were obtained from http://credittrends.moodys.com/.
[4] Data represents January - September, 2020.

Northern Indiana Public Service Company

Treasury and Utility Bond Yields

Line	Date	Treasury Bond Yield[1] (1)	"A" Rated Utility Bond Yield[2] (2)	"Baa" Rated Utility Bond Yield[2] (3)
1	10/16/20	1.52%	2.90%	3.24%
2	10/09/20	1.58%	2.97%	3.30%
3	10/02/20	1.48%	2.93%	3.28%
4	09/25/20	1.40%	2.86%	3.19%
5	09/18/20	1.45%	2.86%	3.18%
6	09/11/20	1.42%	2.83%	3.16%
7	09/04/20	1.46%	2.87%	3.19%
8	08/28/20	1.52%	2.92%	3.24%
9	08/21/20	1.35%	2.74%	3.06%
10	08/14/20	1.45%	2.79%	3.11%
11	08/07/20	1.23%	2.59%	2.93%
12	07/31/20	1.20%	2.56%	2.93%
13	07/24/20	1.23%	2.59%	2.97%
14	**Average**	**1.41%**	**2.80%**	**3.14%**
15	**Spread To Treasury**		**1.39%**	**1.73%**

Sources:
[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[2] http://credittrends.moodys.com/.

Northern Indiana Public Service Company

2019 Depreciation Expense by FERC Account

Line	FERC Account	2019 Gross Plant-In-Service[1]	Depreciation Rate[2]	2019 Depreciation Expense
		(1)	(2)	(3)
	Transmission			
1	367	$517,078,309	1.19%	$6,153,232
2	369	96,554,218	2.18%	2,104,882
3	370[3]	0	7.34%	0
4	Total Transmission			8,258,114
	Distribution			
5	376	940,091,158	1.74%	16,373,639
6	380	672,070,304	2.87%	19,287,851
7	383	104,338,113	1.04%	1,085,116
8	Total Distribution			36,746,606
	Storage			
9	353	5,399,799	1.57%	84,777
10	354	20,753,668	2.22%	460,731
11	356	2,803,009	1.35%	37,841
12	361	9,109,214	2.05%	186,739
13	Total Storage			770,088
14	**Total**	**$2,368,197,792**		**$45,774,808**

Sources:

[1]Northern Indiana Public Service Company 2019 FERC Form 2.

[2]Cause No. 44988, Petitioner's Exhibit No. 10, Attachment 10-B at VI-4 - VI-7.

[3]Cause No. 44688, Petitioner's Exhibit No. 10, Attachment 10-B at VI-5 - VI-14.

Northern Indiana Public Service Company

Monthly "Baa" Utility Bond Yields

Line	Month	"Baa" Rated Utility Bond Yield[1] (1)
1	January 2020	3.60%
2	February	3.42%
3	March	3.96%
4	April	3.82%
5	May	3.63%
6	June	3.44%
7	July	3.09%
8	August	3.06%
9	September	3.17%
10	Average	3.47%

Sources:
[1] http://credittrends.moodys.com/.

Northern Indiana Public Service Company

Projected Growth Rates and Cost of Equity Estimates
(Gas Utilities)

			Growth										
Line	**Gas Utility Group**	**Dividend Yield**	**Yahoo Finance EPS Growth**	**Zacks EPS Growth**	**Value Line EPS Growth**	**Value Line Retention Growth**	**Average Historical EPS**	**Yahoo Finance EPS COE**	**Zacks EPS COE**	**Value Line EPS COE**	**Value Line Ret. Growth COE**	**Historical EPS COE**	**Analysts EPS COE**
		(1)	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)**	**(10)**	**(11)**	**(12)**
1	Atmos Energy Corporation	2.4%	7.1%	7.2%	7.0%	4.5%	8.5%	9.5%	9.6%	9.4%	6.9%	10.9%	9.5%
2	New Jersey Resources Corporation	3.9%	6.0%	8.0%	2.5%	3.4%	6.5%	9.9%	11.9%	6.4%	7.3%	10.4%	9.4%
3	Northwest Natural Holding Company	3.1%	3.8%	5.0%	22.5%	3.9%	-14.3%	6.9%	8.1%	25.6%	7.0%	NMF	13.5%
4	ONE Gas, Inc.	2.8%	5.0%	5.5%	7.0%	3.8%	N/A	7.8%	8.3%	9.8%	6.6%	N/A	8.6%
5	South Jersey Industries, Inc.	4.7%	4.6%	N/A	9.5%	4.0%	-0.5%	9.3%	N/A	14.2%	8.7%	4.2%	11.8%
6	Southwest Gas Holdings, Inc.	3.7%	8.2%	6.0%	8.0%	4.5%	5.8%	11.9%	9.7%	11.7%	8.2%	9.5%	11.1%
7	Spire Inc.	3.5%	4.7%	5.2%	5.5%	2.8%	6.5%	8.2%	8.7%	9.0%	6.3%	10.0%	8.6%
8	**Average**	3.4%	5.6%	6.2%	8.9%	3.8%	2.1%	9.1%	9.4%	12.3%	7.3%	9.0%	10.4%
9	**Median**	3.5%	5.0%	5.8%	7.0%	3.9%	6.2%	9.3%	9.2%	9.8%	7.0%	10.0%	9.5%
10	**Consensus Analysts Growth DCF Return***		**9.2%**										
11	**Low-End Threshold**							5.9%	5.9%	5.9%	5.9%	5.9%	5.9%
12	**Average DCF Results - Pre-Elimination**							9.1%	9.4%	12.3%	7.3%	9.0%	10.4%
13	**150% High-End Threshold**							13.6%	14.1%	18.5%	10.9%	13.5%	15.5%

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Source:
Petitioner's Exhibit No. 4 Attachment 4-A, Schedule 2, Pages 1 and 2.
*Average of Median COE from Yahoo Finance and Zacks.

Northern Indiana Public Service Company

Projected Growth Rates and Cost of Equity Estimates
(Combination Utilities)

			Growth											
Line	Combination Utility Group	Dividend Yield	Yahoo Finance EPS Growth	Zacks EPS Growth	Value Line EPS Growth	Value Line Retention Growth	Average Historical EPS	Yahoo Finance EPS COE	Zacks EPS COE	Value Line EPS COE	Value Line Ret. Growth COE	Historical EPS COE	Analysts EPS COE
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	Alliant Energy Corporation	3.1%	5.8%	5.7%	6.5%	3.7%	5.0%	8.9%	8.8%	9.6%	6.8%	8.1%	9.1%
2	Black Hills Corporation	3.4%	5.8%	4.2%	5.0%	3.8%	8.8%	9.2%	7.6%	8.4%	7.2%	12.2%	8.4%
3	CenterPoint Energy, Inc.	7.3%	2.8%	4.9%	6.5%	3.1%	0.0%	10.1%	12.2%	13.8%	10.4%	7.3%	12.0%
4	CMS Energy Corporation	2.8%	7.5%	6.0%	7.5%	5.3%	8.3%	10.3%	8.8%	10.3%	8.1%	11.1%	9.8%
5	Consolidated Edison, Inc.	3.8%	2.4%	2.0%	3.0%	2.4%	2.3%	6.2%	5.8%	6.8%	6.2%	6.1%	6.3%
6	Eversource Energy	2.7%	5.6%	5.8%	5.5%	3.5%	7.5%	8.3%	8.5%	8.2%	6.2%	10.2%	8.3%
7	MGE Energy, Inc.	2.2%	4.0%	N/A	5.5%	4.8%	3.5%	6.2%	N/A	7.7%	7.0%	5.7%	7.0%
8	NorthWestern Corporation	3.8%	3.2%	3.5%	2.0%	2.6%	7.8%	7.0%	7.3%	5.8%	6.4%	11.6%	6.7%
9	Sempra Energy	3.6%	11.9%	8.1%	11.0%	4.4%	1.5%	15.5%	11.7%	14.6%	8.0%	5.1%	13.9%
10	WEC Energy Group, Inc.	2.8%	6.2%	6.2%	6.0%	4.0%	7.3%	9.0%	9.0%	8.8%	6.8%	10.1%	8.9%
11	**Average**	3.6%	5.5%	5.2%	5.9%	3.8%	5.2%	9.1%	8.9%	9.4%	7.3%	8.8%	9.0%
12	**Median**	3.3%	5.7%	5.7%	5.8%	3.8%	6.2%	9.0%	8.8%	8.6%	6.9%	9.1%	8.7%
13	**Consensus Analysts Growth DCF Return***		**8.9%**										
14	**Low-End Threshold**							5.9%	5.9%	5.9%	5.9%	5.9%	5.9%
15	**Average DCF Results - Pre-Elimination**							9.1%	8.9%	9.4%	7.3%	8.8%	9.0%
16	**150% High-End Threshold**							13.6%	13.3%	14.1%	11.0%	13.1%	13.6%

Source:
Petitioner's Exhibit No. 4 Attachment 4-A, Schedule 3, Pages 1 and 2.
*Average of Median COE from Yahoo Finance and Zacks.

Northern Indiana Public Service Company

Historical Betas
(Gas Utilities)

Line	Company	Rea Beta	Historical Average	3Q20	2Q20	1Q20	4Q19	3Q19	2Q19	1Q19	4Q18	3Q18	2Q18	1Q18	4Q17	3Q17	2Q17	1Q17	4Q16	3Q16	2Q16	1Q16	4Q15	3Q15	2Q15	1Q15	4Q14	3Q14
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)
1	Atmos Energy Corporation	0.80	0.71	0.80	0.80	0.55	0.60	0.60	0.65	0.60	0.60	0.60	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.75	0.75	0.80	0.80	0.85	0.85	0.85	0.80	0.80
2	New Jersey Resources Corporation	0.90	0.77	0.90	0.90	0.65	0.70	0.70	0.70	0.70	0.70	0.70	0.80	0.75	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.85	0.80	0.80	0.80	0.80
3	Northwest Natural Holding Company	0.80	0.66	0.80	0.80	0.55	0.60	0.60	0.60	0.65	0.60	0.65	0.70	0.65	0.70	0.70	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.70	0.70	0.70	0.70
4	ONE Gas, Inc.	0.80	0.68	0.80	0.80	0.60	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.70	0.70	0.70	0.70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
5	South Jersey Industries, Inc.	1.00	0.82	1.00	0.95	0.80	0.80	0.80	0.80	0.85	0.80	0.75	0.85	0.80	0.85	0.85	0.80	0.80	0.80	0.80	0.80	0.85	0.80	0.85	0.85	0.80	0.80	0.80
6	Southwest Gas Holdings, Inc.	0.90	0.77	0.90	0.90	0.65	0.70	0.70	0.70	0.70	0.70	0.75	0.80	0.75	0.80	0.75	0.75	0.75	0.75	0.75	0.75	0.80	0.80	0.85	0.85	0.85	0.85	0.85
7	Spire Inc.	0.80	0.69	0.80	0.80	0.60	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.65	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
8	**Average**	0.86	0.73	0.86	0.85	0.63	0.67	0.67	0.68	0.69	0.67	0.68	0.75	0.71	0.75	0.74	0.73	0.73	0.73	0.74	0.74	0.77	0.76	0.80	0.79	0.78	0.78	0.78
9	**Minimum**		0.63																									
10	**Maximum**		0.86																									

Source: Value Line Reports, multiple dates

Northern Indiana Public Service Company

Historical Betas
(Combination Utilities)

Line	Company	Rea Beta	Historical Average	3Q20	2Q20	1Q20	4Q19	3Q19	2Q19	1Q19	4Q18	3Q18	2Q18	1Q18	4Q17	3Q17	2Q17	1Q17	4Q16	3Q16	2Q16	1Q16	4Q15	3Q15	2Q15	1Q15	4Q14	3Q14
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)
1	Alliant Energy Corporation	0.85	0.71	0.85	0.80	0.55	0.60	0.60	0.60	0.65	0.60	0.65	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.75	0.75	0.80	0.80	0.80	0.80	0.80	0.80	0.80
2	Black Hills Corporation	0.95	0.85	1.00	0.65	0.70	0.70	0.75	0.80	0.75	0.80	0.85	0.90	0.90	0.90	0.85	0.85	0.90	0.90	0.90	0.90	0.90	0.95	0.95	0.95	0.90	0.90	0.85
3	CenterPoint Energy, Inc.	1.10	0.84	1.10	1.15	0.70	0.80	0.80	0.80	0.80	0.85	0.85	0.90	0.85	0.90	0.90	0.85	0.85	0.85	0.80	0.85	0.85	0.85	0.80	0.80	0.80	0.75	0.75
4	CMS Energy Corporation	0.80	0.65	0.80	0.80	0.50	0.50	0.55	0.55	0.55	0.55	0.55	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.75	0.75	0.70	0.75	0.75	0.70	0.75
5	Consolidated Edison, Inc.	0.75	0.53	0.75	0.75	0.40	0.45	0.45	0.45	0.45	0.45	0.45	0.50	0.50	0.50	0.50	0.50	0.55	0.55	0.55	0.55	0.55	0.60	0.60	0.60	0.60	0.60	0.60
6	Eversource Energy	0.90	0.68	0.90	0.90	0.55	0.55	0.60	0.60	0.60	0.60	0.60	0.65	0.65	0.65	0.65	0.65	0.70	0.70	0.70	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
7	MGE Energy, Inc.	0.70	0.68	0.70	0.70	0.50	0.55	0.55	0.55	0.60	0.60	0.65	0.70	0.70	0.75	0.75	0.75	0.70	0.70	0.70	0.70	0.70	0.75	0.75	0.75	0.70	0.70	0.70
8	NorthWestern Corporation	0.90	0.66	0.90	0.55	0.60	0.60	0.60	0.60	0.55	0.60	0.65	0.65	0.70	0.70	0.65	0.65	0.70	0.70	0.70	0.70	0.70	0.70	0.75	0.70	0.70	0.70	0.70
9	Sempra Energy	0.95	0.77	0.95	0.65	0.70	0.75	0.75	0.75	0.75	0.75	0.75	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.85	0.80	0.80	0.80	0.80	0.75	0.75	0.75
10	WEC Energy Group, Inc.	0.80	0.61	0.80	0.80	0.45	0.50	0.50	0.50	0.55	0.50	0.55	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.65	0.65	0.70	0.70	0.70	0.70	0.65	0.65	0.65
11	**Average**	0.87	0.70	0.88	0.78	0.57	0.60	0.62	0.62	0.63	0.63	0.66	0.71	0.71	0.72	0.71	0.70	0.72	0.72	0.72	0.74	0.75	0.77	0.76	0.76	0.74	0.73	0.73
12	**Minimum**		0.57																									
13	**Maximum**		0.88																									

Source: Value Line Reports, multiple dates.