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INDIANA UTILITY
REGULATORY COMMISSION

VERIFIED DIRECT TESTIMONY OF FRANK A. SHAMBO

Page No.

<u>Witness Information</u>

Q1. Please state your name, business address and title.

A1. My name is Frank A. Shambo. My business address is 150 W. Market Street, Suite 600, Indianapolis, Indiana 46204. I am Vice President, Regulatory and Legislative Affairs for Northern Indiana Public Service Company ("NIPSCO" or the "Company").

Q2. Please briefly describe your educational and business experience.

A2. I graduated from Western Illinois University with a Bachelor of Science Degree in Accounting. I also have a Masters of Management Degree in economics and finance from the J.L. Kellogg Graduate School of Management, Northwestern University. During the period 1980 through 1996, I was employed by MidCon, an Occidental Petroleum Company, in various capacities. During the period 1987 through 1996, I was employed in the Marketing Department of Natural Gas Pipeline Company of America (a division of MidCon) ultimately obtaining the position of Director of Marketing for Utility Sales. In 1996, I was a co-founder of mc2, a start-up company and an early entrant into the unregulated retail energy market and served as the Director of Marketing/Finance through 1998 when the company was sold. In 1998 through 2000, I served as Vice President, Finance and Business Development for en*able LLC, which was also a start-up company working in concert with utilities across the country on new products and marketing efforts. Beginning in 2000, I served as a consultant for various utilities until my employment by NIPSCO as Director, Regulatory and Government Policy in January 2004. I assumed my current position of Vice President, Regulatory and Legislative Affairs on April 1, 2008.

Q3. Have you previously testified before this or any other regulatory commission?

A3. Yes. Among other proceedings, I testified before the Indiana Utility Regulatory Commission ("Commission") in NIPSCO's 2008 Electric Rate Case, Cause No. 43526; NIPSCO's 2010 Electric Rate Case, Cause No. 43969; and NIPSCO's 2010 natural gas rate case, Cause No. 43894. I also prefiled testimony on behalf of NIPSCO in Cause No. 43976, Indiana Finance Authority and Indiana Gasification, LLC request for approval of a Substitute Natural Gas Purchase and Sale Agreement; Cause Nos. 43866 and 44046 requesting approval of bridge contracts between NIPSCO and

NLMK Indiana and BP Products North America Inc., respectively; Cause No. 43941, the merger filing among NIPSCO, Northern Indiana Fuel & Light Company Inc. ("NIFL") and Kokomo Gas & Fuel Company ("Kokomo"); Cause No. 43942, Kokomo's 2010 natural gas rate case; and Cause No. 43943, NIFL's 2010 natural gas rate case, Cause No. 44012 (Phase III) requesting a Certificate of Public Convenience and Necessity for environmental projects, Cause No. 44370, NIPSCO's request for approval of a 7-year plan for eligible transmission, distribution and storage system improvements, and Cause No. 44371, NIPSCO's request for approval of a Transmission, Distribution and Storage System Improvement Charge Rate Schedule.

Q4. Are you sponsoring any attachments to your testimony in this Cause?

A4. Yes. I am sponsoring <u>Attachment 2-A through 2-C</u> all of which were prepared by me or under my direction and supervision. <u>Attachment 2-A</u> is a copy of the petition filed in this Cause. <u>Attachment 2-B</u> shows 2013 sales to industrial customers as a percentage of total jurisdictional sales. <u>Attachment 2-C</u> shows a usage distribution of electric residential customers.

<u>Purpose of Testimony</u>

Q5. What is the purpose of your testimony?

A5. The purpose of my testimony is to:

(1) discuss Senate Enrolled Act 560 and other statutory requirements;

(2) provide a brief background of NIPSCO's existing electric rates;

(3) explain why NIPSCO is filing this case;

(4) explain NIPSCO's approach to this case and its philosophy as it moves forward in this proceeding;

(5) provide an overview of the objectives NIPSCO used in developing the rates proposed in this proceeding;

(6) explain key cost allocation and rate design parameters used in the development of rates;

(7) provide a summary of NIPSCO's requested tariff relief;

(8) discuss the impact of NIPSCO's plan to retire Bailly Unit 8 at the same time as Bailly Unit 7 (no later than 2023); and

(9) discuss the appropriate fair return on its used and useful assets as proposed in this proceeding.

<u>**Senate Enrolled Act 560 and Other Statutory Requirements**</u>

Q6. How does Senate Enrolled Act 560 affect this proceeding?

A6. Senate Enrolled Act 560 was passed by the Indiana General Assembly in April of 2013, codified as Ind. Code § 8-1-2-42.7 ("SEA560"). The law changed the process pertaining to rate cases in Indiana.

Notably, SEA560 instituted a 300-day timeline for rate case procedural schedules. Relatedly, it allows utilities to implement 50% of the proposed rate increase if the Commission does not issue an Order within 300 days after the filing date. These temporary rates would be subject to refund if the final Commission-approved rates are less than the interim rates. The 300-day timeline may only be extended for good cause.

Second, SEA560 allows utilities to elect a historical test year, a forward-looking test year, or a hybrid test year that includes both historic and projected data.

Third, SEA560 provides that the close of a historical test year must be within 270 days of the petition date. On July 3, 2013, the Commission issued General Administrative Order ("GAO") 2013-5, which recognized that a standard procedural schedule will help ensure that rate cases submitted under Ind. Code § 8-1-2-42.7 will be completed within the 300-day timeframe established by SEA560. The GAO also recommended rate case best practices to facilitate a more efficient and timely process for identifying the critical issues in rate cases.

Q7. Is NIPSCO following the rate case best practices set forth in GAO 2013-5?

A7. Yes.

Q8. Is NIPSCO using a future or hybrid test year?

A8. No. NIPSCO elected to use a historical test year in this case. NIPSCO prepared its case based on the 12-month test year ending March 31, 2015, which is within 270 days of the date of the Petition filed in this Cause. NIPSCO's request aligns with GAO 2013-5. In addition, NIPSCO does not propose any new trackers, which should facilitate the Commission's and intervening parties' review of the case well within the 300-day timeline. The scope of this case is narrow.

Q9. Is NIPSCO proposing a 300-day procedural schedule?

A9. Yes. Prior to filing, NIPSCO discussed the 300-day schedule with interested stakeholders. Based upon feedback from those stakeholders, we have proposed certain revisions to the specific dates that would be set based upon GAO 2013-5. The revisions impact certain milestones prior to the evidentiary hearing. This agreed upon schedule is being filed with the Commission contemporaneous with the filing of NIPSCO's petition and case-in-chief.

Q10. Does NIPSCO's request in this proceeding satisfy the statutory "fifteen month rule" for a general rate case?

A10. Yes. Consistent with Ind. Code § 8-1-2-42(a), NIPSCO's Petition in this Cause was filed more than 15 months after November 19, 2010, the date the Company filed its petition in Cause No. 43969, which was the most recent request for a general increase in the Company's basic electric rates and charges.

<u>Existing Electric Rates</u>

Q11. When were NIPSCO's current basic electric rates and charges established?

A11. NIPSCO's current basic electric rates and charges were approved in the Commission's December 21, 2011 Order in Cause No. 43969 ("43969 Order"), wherein the Commission approved a Stipulation and Settlement

Agreement ("43969 Settlement") between NIPSCO and a majority of the intervenors (the "43969 Rate Case").[1] Those new basic rates and charges went into effect on December 27, 2011. The 43969 Order approved, among other items, an increase in NIPSCO's basic rates and charges.

Q12. Did NIPSCO conduct a jurisdictional cost of service study in the 43969 Rate Case?

A12. No. NIPSCO proposed that all assets be considered jurisdictional, but that the revenue from its provision of service to certain customers pursuant to FERC-governed contracts and tariffs be considered as an offset to its revenue requirements.

Q13. What were the significant aspects of the 43969 Settlement?

A13. The 43969 Settlement resolved all of the issues in the 43969 Rate Case. In its order approving the 43969 Settlement, the Commission stated: "[T]he settlement provides a just and reasonable resolution of all matters pending before the Commission in this case. It reflects the significant collaboration and compromise inherent in serious negotiations among a

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[1] NIPSCO, the OUCC, NLMK Indiana f/k/a Beta Steel Corporation, Indiana Municipal Utilities Group, and NIPSCO Industrial Group were parties to the 43969 Settlement.

diverse group of interests."[2] The 43969 Settlement specifically included, in part, the following significant provisions:

- a base rate revenue requirement of $1.355 billion;
- an authorized net operating income ("NOI") of $189 million;
- a 10.2% cost of equity and a 6.98% weighted average cost of capital;
- use of at least 60% debt to finance any environmental project for which NIPSCO receives a Certificate of Public Convenience & Necessity in Cause No. 44012;
- an initial Fuel Adjustment Clause earnings bank of ($200) million;
- demand allocators for both general revenue apportionment and for specific trackers; and
- interruptible and temporary service riders.

Q14. Have there been any significant changes since the 43969 Order?

A14. Yes. Significantly, NIPSCO has implemented a new multi-pollutant compliance plan;[3] established an infrastructure modernization plan; continued to implement demand-side management and energy efficiency programs;[4] implemented a Green Power Rider and a Feed-in Tariff rate;[5] met a number of new environmental mandates or requirements, including

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[2] 43969 Order at 71.
[3] Cause No. 44012, Phases I, II and III.
[4] Cause Nos. 43618, 43912, 44363 and 44496.
[5] Cause Nos. 44198, 44520, 43922 and 44393.

compliance with Mercury and Air Toxics Standards; and met a number of new critical infrastructure requirements established by the North American Electric Reliability Corporation.[6] In addition, the Midcontinent Independent System Operator, Inc. ("MISO") construct continues to evolve, which has impacted jurisdictional activity through NIPSCO's RTO tracker mechanism. As discussed below, NIPSCO is continuing to construct two key Multi-Value Projects ("MVP") for the MISO transmission system, although as described below, these MVP facilities are non-jurisdictional for state ratemaking purposes.

Q15. Have customers' bills been impacted by these changes?

A15. Yes. NIPSCO has been authorized to recover the cost of some of the investments, such as environmental assets, through tracking mechanisms, which have resulted in increases in customers' bills since the current base rates went into effect on December 27, 2011. It should be noted that, as shown in Figure 1 below, NIPSCO's total residential bill has grown at a lower rate, on a percentage basis, than any of the other investor-owned

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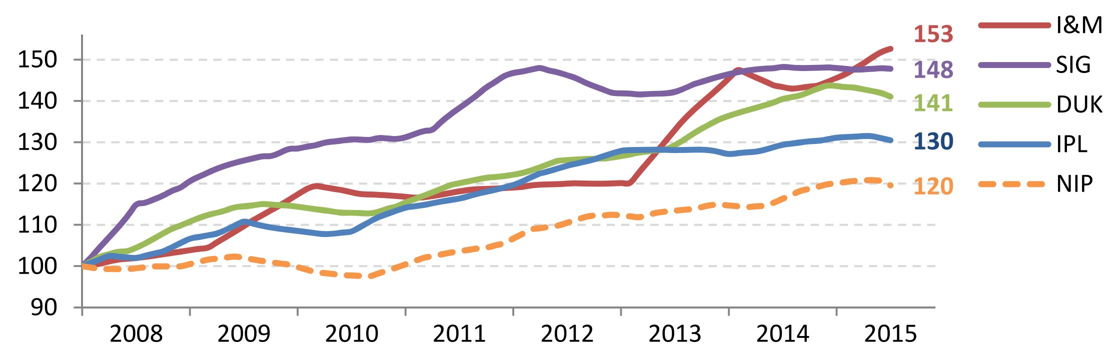
[6] Cause Nos. 44311 and 44340.

electric utilities in Indiana since the end of 2007, the end of the Company's test year in its rate case in Cause No. 43526.

Figure 1.
Growth of 1,000 kWh/month residential bill
(trailing 12 month average, Jan 2008 = 100)



In addition, as noted in Table 7 of the Commission's Electricity Division's 2015 Residential Bill Survey of jurisdictional electric utilities, of the 14 utilities, NIPSCO has the lowest residential bill change for the last 10 years (2005-2015).

<u>Key Drivers</u>

Q16. Please describe the key drivers that have caused the Company to request the change in rates proposed in this proceeding.

A16. NIPSCO is filing this case to (i) honor its commitment in the Stipulation and Settlement Agreement on Remand (the "Remand Settlement") in

Consolidated Cause Nos. 44370 and 44371 (the "Remand Proceeding") to file a rate case before the end of 2015; (ii) reflect in base rates the recent capital investments to NIPSCO's electric system, including infrastructure modernization and environmental controls; (iii) update and revise its depreciation rates to reflect, among other things, the most recent information regarding planned retirements of its generating units; (iv) align its rates and charges with its updated cost of electric service and to address prolonged under-earnings; and (v) update the allocation of jurisdictional costs to the various rate classes, many of which now represent a different percentage of energy and demand on NIPSCO's electric system especially in light of recent industrial volume declines.

Q17. Is this filing related to the Remand Settlement involving NIPSCO's Transmission, Distribution, Storage System Improvement Charge ("TDSIC") proceeding?

A17. Yes, as part of the Remand Settlement, NIPSCO agreed to file an electric rate case prior to December 31, 2015.[7] However, I would note, that as we

[7] On September 23, 2015, the Commission issued an Order on Remand in Consolidated Cause Nos. 44370 and 44371 whereby the Commission denied the Remand Settlement in its entirety and ordered NIPSCO to refund monies collected through Rider 688. On September 29, 2015, the Settling Parties and Indiana Municipal Utilities Group filed a Verified Petition for Rehearing and Reconsideration or, Alternatively, Commission Clarification and Guidance.

stated in hearings held on SEA560, NIPSCO was going to need to make significant infrastructure investments, and without TDSIC recovery, NIPSCO stated that it would be necessary to file rate cases to timely recover the return on and of these expenditures.

Q18. Briefly describe NIPSCO's increase in operating expenses since the 43969 Order.

A18. The 43969 Order determined NIPSCO's annual operating expenses to be $363.2 million. Since that time, approximately $30 million of additional operation and maintenance ("O&M") expenses generally related to capital investments have been recovered in trackers. The Company's operating expenses were $491.6 million in the twelve months ending March 31, 2015, and $506.6 million, including pro forma adjustments. NIPSCO filed this proceeding, in part, to address this increase in O&M expenses and the impact on its cost of service, which should be reflected in its rates.

Q19. How has the increase in operating expenses impacted NIPSCO's earnings situation?

A19. The 43969 Order determined NIPSCO's electric regulatory (jurisdictional) NOI to be approximately $190 million. Since that time, the Commission has approved various Company requests to recover certain additions to NIPSCO's jurisdictional plant-in-service that have caused NIPSCO's authorized NOI to increase to $229.2 million as of June 30, 2015 (values taken from the Company's filing in FAC 108). As of June 30, 2015, NIPSCO's electric regulatory (jurisdictional) NOI under present rates, as calculated in its FAC 108, was $163.5 million, almost $65.7 million less than its adjusted, authorized level of $229.2 million.[8] This significant deficit in earnings is the result of NIPSCO's increase in O&M expense, and is driving the need to file this rate case. Figure 2 illustrates that NIPSCO has under-earned its authorized NOI since its last rate case. Consequently, NIPSCO has experienced a commensurate increase in its earnings bank from $200 million, the level set by the Commission in the 43969 Order, to $733.8 million on June 30, 2015.

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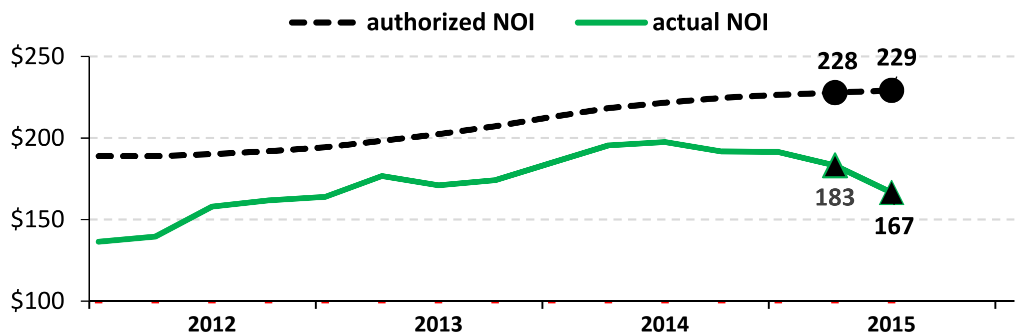
[8] Cause No. 38706-FAC-107, Exhibit No. 2-A, page 1 of 5.

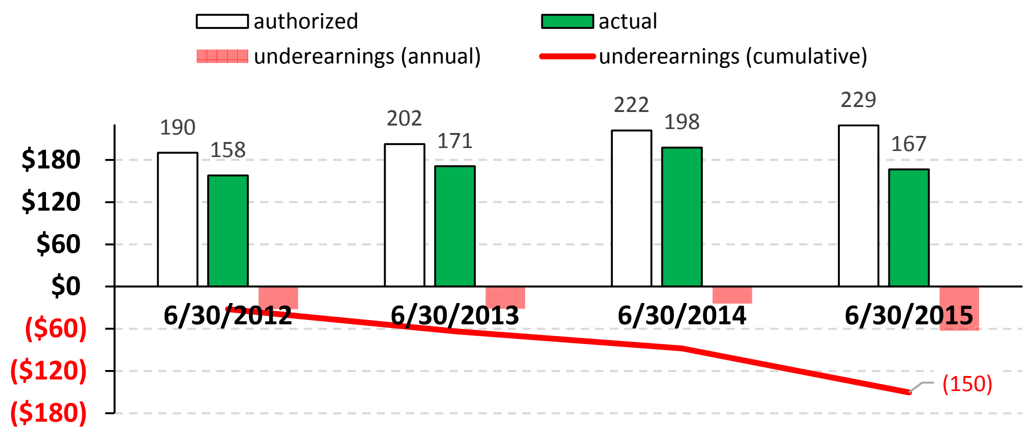
Figure 2.
NIPSCO's Electric NOI ($Mil, trailing 12 months)



Q20. How has NIPSCO's actual annual NOI compared to its authorized NOI since the last time the Company filed for rate relief?

A20. Figure 3 illustrates that NIPSCO's NOI has been less than the level authorized by the Commission in each of the last four years. From June 30, 2011 (six months before NIPSCO's current rates went into effect) through June 30, 2015 (the most recent information available at the time of this filing), the Company under-earned its authorized NOI by over $150 million.

Figure 3.
NIPSCO NOI ($M)



<u>Approach and Philosophy</u>

Q21. Please explain NIPSCO's approach to this proceeding.

A21. NIPSCO seeks to promote simplicity, transparency and collaboration with our stakeholders, as well as to respond to customers' needs, and reach a balanced set of proposals that is fair and reasonable. NIPSCO took this approach in its 43969 Rate Case, and it yielded positive results as evidenced by a comprehensive settlement agreement that resolved a number of contentious issues spanning two major rate case filings. The Company invites the Commission and the other stakeholders to ask questions about its proposals. NIPSCO believes it will best meet the objectives of this filing by ensuring that all the parties to this proceeding fully understand the Company's methodologies. In order to achieve the level of transparency and collaboration NIPSCO desires, the Company encourages the Commission to establish a technical conference within the GAO 2013-5 schedule to address questions related to NIPSCO's case-in-chief.

Q22. How did NIPSCO engage its stakeholders (including some of its largest customers) prior to filing this case?

A22. NIPSCO engaged stakeholders on a prefiling basis in July 2015. NIPSCO held a kickoff meeting on August 4, 2015, and it has been engaged with stakeholders, including large industrial customers, on a one-on-one basis since that time. NIPSCO expects these discussions to continue beyond the filing of its case-in-chief.

<u>Policy Objectives</u>

Q23. What are NIPSCO's policy objectives in this proceeding?

A23. In this rate case, NIPSCO seeks to achieve rates that are reasonable and just. Such rates will better align the recovery of costs from the customers that drive those costs, as well as afford the Company a reasonable opportunity to recover its expenses and earn an appropriate return on its used and useful assets.

Q24. Please further explain the policy objective that rates are reasonable and just.

A24. Indiana law requires that NIPSCO's rates and charges be reasonable and just.[9] NIPSCO believes this mandate requires the Company to strike an appropriate balance between the desire of its customers for safe and reliable service at reasonable rates and the need to attract investors with an opportunity to earn an appropriate return of and on the capital they invested to purchase or construct the Company's used and useful assets. NIPSCO believes this mandate also requires that the Company's rates achieve a reasonable level of equity between customer classes.

This latter requirement can be very challenging. NIPSCO believes that the cost allocation and rate design methods proposed in this case strike an equitable balance between the different interests of its customers, and therefore result in proposed rates that are reasonable and just.

Q25. Please discuss NIPSCO's objective that the rates and charges should improve alignment of cost recovery with cost causation.

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[9] Ind. Code § 8-1-2-4.

A25. Utility rates should be designed so that the customers who cause expenses to be incurred pay for those expenses. This topic will be discussed in greater detail later in my testimony, but there are three key aspects to improving alignment of cost recovery to cost causation: (i) fixed cost recovery through fixed charges; (ii) recovery of costs from the customers that cause the costs; and (iii) the proper alignment of pricing signals and incentives.

Q26. Please discuss NIPSCO's objective that the rates and charges should afford the Company a reasonable opportunity to recover its expenses and provide an appropriate return on its used and useful assets.

A26. In this proceeding, NIPSCO is proposing rates that, at NIPSCO's test year adjusted energy and demand volumes, will allow the Company to recover both its prudently incurred costs to serve its customers and a fair return for its investors. These are both necessary to continue to provide safe and reliable electric service to our customers.

<u>Key Issues</u>

Q27. What are the key issues that impact this case?

A27. NIPSCO envisions the three key issues that impact this case as follows:

First, how should NIPSCO allocate costs and design its rates to best balance the differing interests of its customer classes? This case, as I discuss further below, will entail views about how the costs should be allocated to the various customer classes.

Second, how should NIPSCO allocate costs and design rates given its large exposure to industrial customers? Attachment 2-B illustrates that NIPSCO has the highest industrial demand, as a percentage of total demand, of the 60 largest electric utilities, ranked by sales, in the country.[10] Service to industrial customers in this large proportion creates a unique risk to NIPSCO relative to any other electric utility. NIPSCO's largest ten customers comprise over 40% of NIPSCO's sales and they are subject to international forces. This is a significant risk because of the companies' large energy requirements and the significant decrease in demand that results when a large industrial customer shuts down its operations or decides to decrease production due to economic factors. On March 1, 2015, ArcelorMittal shut down its Indiana Harbor Long Carbon

[10] The data underlying Attachment 2-B comes from FERC Form 1 filings, via SNL. The data is based upon bundled sales (sales to customers that pay an electric utility for both generation and delivery of power). The supporting workpaper for Attachment 2-B also shows the statistics when "delivery only" volumes are included. NIPSCO's position as the utility most exposed to industrial sales does not change when delivery sales volumes are included in the calculation.

facility.[11] In May 2015, U.S. Steel shut down its Gary Works coke plant.[12] NIPSCO anticipates an annualized 2.8% reduction in NIPSCO's industrial sales volumes as a result of these closures. This reduction would be the equivalent of losing 33,497 households of annual usage. NIPSCO anticipates associated revenues decreasing by about 2.2%. In addition, industrial customers have lately been expressing interest in procuring their energy through other avenues. NIPSCO Witnesses Curt A. Westerhausen and J. Stephen Gaske address the recent load reductions of ArcelorMittal and U.S. Steel issues by including the impacts of these two closures in our revenue requirement and rate calculations.

Finally, how will increasing customer interest in distributed generation technologies and energy efficiency measures affect NIPSCO's ability to recover its expenses, including its cost of capital? This issue is similar to the one above. If rates are designed to recover fixed costs through energy charges, a reduction in sales due to distributed generation technology will cause NIPSCO to under-recover its fixed costs and eventually shift those costs to other customers. I address this issue later in my testimony.

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11 *ArcelorMittal to lay off 304 in steel plant closing* (IBJ, January 26, 2015).

12 *U.S. Steel closing Gary Works coke plant* (Chicago Tribune, February 26, 2015).

<u>Bailly Unit 8 Depreciation</u>

Q28. What is NIPSCO proposing in this case regarding Bailly Unit 8?

A28. The Company's current plan is to retire Bailly Unit 8 at the same time as Bailly Unit 7 (no later than 2023), which is a change from the separate retirement dates used in NIPSCO's 2014 Integrated Resource Plan (2023 for Unit 7 and 2029 for Unit 8). Those retirement dates were based on a 60-year life for each unit. As discussed by NIPSCO Witness Michael Hooper, for a variety of reasons, NIPSCO has determined it makes more sense to retire these coal units at the same time and no later than 2023. NIPSCO is therefore proposing to change the depreciation rates for Bailly Unit 8 to account for this earlier retirement. Specifically, the retirement date for Unit 8 used for purposes of the depreciation study sponsored by NIPSCO Witness John J. Spanos will change from 2029 to 2023 to match the retirement date for Unit 7 used for purposes of the depreciation study. This is appropriate because new depreciation rates should match the expected life of the underlying assets. Matching accounting and ratemaking treatment with that expected asset life is fair for current and future customers and is consistent with establishing reasonable and just rates.

<u>Overview of Proposed Service Structure, Cost Allocation and Rate Design</u>

Q29. What is a utility's service structure?

A29. A service structure includes all provisions within a utility's tariff. A tariff may include customer, demand and energy charges, and various service characteristics, to implement rates and service options to serve various customer classes with differentiated characteristics. For example, two customers that use the same amount of energy each month may have different costs of service if they require the energy at different voltage levels or use the energy at different times of the day. In this case, the utility may separate these two customers into different rate classes so that the customer whose energy consumption characteristics cause the utility to incur less expense does not unreasonably subsidize the customer whose consumption characteristics cause the utility to incur more expense.

Q30. Did NIPSCO conduct a jurisdictional/non-jurisdictional cost allocation in this proceeding?

A30. No. As discussed previously, similar to our approach in the 43969 Rate Case, while NIPSCO has revenues from FERC-governed contracts and tariffs, the revenues are used as an offset to our revenue requirement and the assets are 100 percent jurisdictional. Subsequent to the 43969 Rate

Case, NIPSCO was given authority to construct two Multi-Value Projects by MISO, a regional transmission organization ("RTO"). As approved in Cause No. 44156-RTO-1, these two projects are non-jurisdictional for state ratemaking purposes.

Q31. Please explain the service structure, cost allocation and rate design objectives.

A31. NIPSCO's proposals reflect the following objectives:

(1) retain the basic service structure established in the 43969 Settlement;

(2) reduce subsidies between and among classes and moderate any rate shock by incorporating gradualism; and

(3) ensure rate design calculations are simple and transparent.

Q32. Is NIPSCO proposing significant changes to its service structure in this proceeding?

A32. No. NIPSCO worked with its stakeholders over the past few years to implement rates from the 43969 Settlement that fairly delineate between the unique energy needs of its customers. The Company appreciates the time these stakeholders have invested in helping NIPSCO implement these efficient energy service offerings. While the Company is proposing revisions to clarify the tariff or the operation of the currently-effective service structure, it will not be proposing any significant changes to its tariff rate schedule offerings.

For example, NIPSCO is not proposing to materially modify its current Riders 675 (Interruptible Industrial Service) or 676 (Back-up, Maintenance and Temporary Industrial Service), which were key pieces to the 43969 Settlement that have provided benefits to the NIPSCO system and customers since December 2011. NIPSCO views these two riders as key elements to its service structure available to large customers, and the Company also believes it is reasonable to maintain their main terms and conditions intact on a going forward basis. Mr. Westerhausen explains these proposals in greater detail.

Q33. Please summarize NIPSCO's proposal regarding its Economic Development Rider ("EDR").

A33. NIPSCO is seeking (i) waiver of the current EDR provision that, upon effectiveness of new base rates, existing EDR contracts would terminate –

i.e., NIPSCO proposes to allow all EDR contracts to continue until the termination date noted in the existing EDR contracts, even if that is beyond the date of new, effective base rates; (ii) ability to defer as a regulatory asset the discounted revenue associated with the EDR contracts in effect during the test year that continue beyond the effective date of new base rates; (iii) a tariff change inside of the EDR that would, on a going-forward basis, provide that EDR contracts would not terminate upon new base rates; and (iv) a tariff change reducing the maximum term of new EDR contracts from 5 years to 3 years.

In summary, NIPSCO is proposing to establish a new EDR framework where (a) EDR contracts remain in effect even after an intervening rate case, (b) the Company bears the cost of the discounted revenue for any contracts entered into after the previous rate case and prior to a subsequent rate case, and (c) following a rate case, NIPSCO will defer the discounted revenue, as a regulatory asset, and recover that total amount in a following rate case.

Q34. Why is NIPSCO proposing these changes to the EDR?

A34. These changes will benefit both the Company's existing EDR customers and its other customers. As the tariff is currently written, existing EDR customers would lose their discounted rates when NIPSCO's new rates go into effect. Granted, the customer was or should have been aware that this risk existed since the tariff provision has been in place since 2011; nonetheless, since these contracts were executed to provide incremental load and incremental economic benefits to the region, it is reasonable to maintain the contracts through their original term. These customers have relied on the discounted rates to support the viability of new investment, and losing those discounts earlier than expected could jeopardize their operations. Furthermore, prospective EDR customers could be deterred from moving their operations to or growing their operations in NIPSCO's service territory if they believe a new rate case could cut short the discounts upon which they rely.

These changes will also benefit existing customers, since new customers and loads decrease each existing customer's necessary contribution to the fixed costs of NIPSCO's electric system. Existing customers should support any provision that encourages new load in the Company's service territory.

The ability to defer the discounted revenue associated with EDR contracts in effect during the test year is necessary because the increased load is included in the test year billing determinants and this would cause NIPSCO to under-recover due to the ongoing discounts beyond effectiveness of new base rates. The amount of this requested deferral is estimated to be approximately $2.3 million annually (based upon the average of the estimated discounted revenue in each of the calendar years 2016 through 2019).

If the Commission approves this waiver and ability to defer, then it is also appropriate to address the length of time that this discount can impact other customers; therefore, NIPSCO is proposing, for new EDR contracts, to reduce of the term of EDR contracts from 5 years to 3 years.

Finally, providing the deferral treatment of discounted revenue after effectiveness of new rates and instituting a term length of 3 years are both consistent with SEA560.[13] In that statute, certain large customers have the ability to petition the Commission to seek a discount to charges for incremental load and benefits to the system, and the statute provides that

[13] Ind. Code § 8-1-2-24.

the utility has the ability to defer the discounted revenues for subsequent recovery in its next base rate case. It is equally appropriate to institute that treatment here. In addition, those discounts under SEA560 are available for a term of 3 years, and NIPSCO seeks to make its rates consistent with that provision. NIPSCO Witness Derric J. Isensee discusses the request for deferral accounting further in his testimony.

Q35. You mentioned before that one of your objectives was to reduce subsidies between and among classes and moderate any rate shock by incorporating gradualism. Briefly describe how NIPSCO arrived at its proposed cost allocation.

A35. First, Mr. Gaske performed a fully allocated cost of service study ("ACOSS" or "Study") for the Company. The Study allocated and applied the costs to current rate classes as follows: (i) production demand costs using the 4 Coincident Peak ("CP") method; (ii) transmission demand costs using the 12-CP method; (iii) sub-transmission, distribution primary and distribution secondary demand costs using the non-coincident peak ("NCP") method; and (iv) various customer-related costs either by the number of customers or based on specific studies. NIPSCO reviewed the impact of that ACOSS on each rate class, and identified that basing rates on an unmitigated basis (or without class subsidies) would yield major impacts to some classes (*e.g.*, a 25.72% increase to residential, a 7.29% decrease to small commercial). NIPSCO found those impacts to be too severe, and is proposing a gradual approach to removing current class subsidies based upon key parameters. Specifically, NIPSCO applied the following methodology:

(1) limit the largest subsidized class (on a total dollar basis), which is the residential class, to an increase approximately half of the total class increase that would occur without any mitigation – i.e., 12.47% when it would otherwise be over 25%;

(2) no customer class revenue increase less than 1.0%;

(3) apply a 75% reduction to the subsidy for large industrial classes (current Rates 632, 633 and 634);

(4) apply an equalized subsidy reduction amount, or percentage, for all other classes; and

(5) eliminate the subsidy for Interdepartmental.

By applying these parameters in this manner, NIPSCO is able to propose either reducing current subsidies or avoiding making notable class subsidies any worse through this rate case. In addition, no one customer class is receiving an increase greater than 150% of the system average increase of 9.17%. The full results can be seen in Mr. Gaske's Attachment 17-G.

Q36. Please explain why the ACOSS allocates production demand costs on the basis of 4-CP.

A36. Mr. Gaske explains the specific coincident peak results and concludes that the results can support either the use of 4-CP or 12-CP methodologies for allocation of production demand costs. Nonetheless, based upon a broader window of time extending back through 2010 and based upon application of the FERC tests, it is apparent that NIPSCO's system has been more consistent with a 4-CP allocation rather than a 12-CP allocation. Using an average of the FERC tests applied to 2010, 2011, 2012, 2013 and the current test year, two of the three FERC tests over this timeframe favor a 4-CP allocation.

Nevertheless, the use of 4-CP versus 12-CP does not dictate the ultimate proposed class increases in this filing. The use of a 12-CP allocation for production costs would still yield an increase of over 17% to the residential class after removing all current subsidies. This is more than 150% of the system average increase of 9.17%. Therefore, the most determinative basis is the principle of gradualism and the application of the mitigation parameters explained above.

Q37. Please explain why NIPSCO is proposing to "mitigate" the effect of moving to rates that are based on the ACOSS.

A37. It is appropriate to mitigate in this filing because of the severe effects moving to a full allocation based upon the ACOSS. Whether it is based upon using a 4-CP or 12-CP allocation for production costs, either method, for example, would yield an impact to the residential class that was nearly, or in excess of twice the system average. The Company considers this to be too excessive in one rate case filing, and is sympathetic to the burden that would be placed on certain customers. For these reasons, NIPSCO has proposed revised base rates applying the mitigation methodology discussed above.

Q38. Please compare the results of the "mitigated" approach to the fully allocated cost of service approach.

A38. Turning to the comparison relative to currently-effective rates after certain adjustments, as presented by Mr. Gaske, the proposed approach equates to an overall requested revenue increase of 12.47% to current residential customers. As the information in the following table demonstrates, the approach is more advantageous to our residential customers. Figure 4 illustrates the differences in revenue (in millions and rounded) regarding a few key rate schedules:

Figure 4
NIPSCO's Revenue Allocation (millions, rounded)

Rate Schedules		Test year	Fully allocated	Mitigation
Rate 611	Residential	$435	$547	$490
Rate 621	General (small)	$206	$191	$223
Rate 623	General (medium)	$166	$173	$181
Rate 624	General (large)	$208	$211	$225
Rate 625	Metal melting	$6	$7	$7
Rate 632	Industrial	$167	$175	$176
Rate 633	Industrial (HLF)	$185	$189	$191
Rate 634	Industrial (Air)	$133	$153	$151
All Other		$103	$111	$113
TOTAL		**$1,609**	**$1,757**	**$1,757**

Q39. How did NIPSCO treat the load designated as interruptible under NIPSCO's current Rider 675 in the ACOSS?

A39. NIPSCO has treated the load the same as outlined in the 43969 Settlement approved by the Commission. Specifically, NIPSCO has treated all load as firm prior to any interruptible election under current Rider 675.

Q40. You also mentioned above that one of your objectives is to ensure rate design calculations are simple and transparent. Please provide an overview of NIPSCO's proposed rate design.

A40. As noted earlier, there are three key aspects to improving alignment of cost recovery to cost causation: (i) fixed cost recovery through fixed charges; (ii) recovery of costs from the customers that cause the costs; and (iii) the proper alignment of pricing signals and incentives. NIPSCO is proposing a rate design that yields a revenue stream that improves the alignment with NIPSCO's underlying cost structure.

Q41. Please explain the proposed changes to the fixed charges for Residential, Commercial, and Industrial rates.

A41. As for residential rate design, NIPSCO proposes to take a relatively small step towards further fixed-variable alignment. Specifically, NIPSCO proposes to increase the customer charge that applies to residential and small commercial customers in a manner that simply improves recovery of the fixed costs to serve the customer and billing functions for customers. The proposed residential customer charge of $20 per month would improve that alignment. Based upon a full allocation of costs in the Study, the customer costs alone support a charge of $22.51, and the full fixed cost would support $83.95. Those costs above $20 are still recovered through a variable charge, or the energy charge. However, noting that the currently-effective monthly customer charge is $11, in the spirit of gradualism, a $20 per customer per month is an appropriate step through this rate case.

Q42. Does a higher fixed monthly customer charge disproportionately harm low income customers?

A42. No. Based upon NIPSCO's information, the average monthly usage for low income customers is higher than the normal population's average monthly usage. Please see <u>Attachment 2-C</u>.

Q43. Regardless of whether the low income customers in NIPSCO's electric territory have an average usage profile less than the total population, does NIPSCO want to assist low income customers?

A43. Yes, but any program should be designed explicitly and intentionally to accomplish this objective of assisting low income customers. Making an assumption that low income customers use less energy than the average residential customer, and, therefore, designing rates to favor lower usage customers in an effort to help these customers, is not an appropriate way to address this issue.

Q44. Is NIPSCO proposing a Low Income Program in this proceeding?

A44. Yes. At the outset, however, I want to be clear that any program that helps low income customers must be designed to explicitly and intentionally accomplish this objective. To accomplish this goal, NIPSCO has included a flat surcharge in its proposed Rate 711 rate schedule of $0.20 per month that will provide a fund of dollars available to all electric customers who receive bill assistance through the Low Income Home Energy Assistance Program (LIHEAP). Specifically, NIPSCO proposes to directly assist with higher summer bills by providing a one-time credit of $50 to the June bill of those eligible customers. This is similar and in addition to the flat electric bill credit applied in the currently operative LIHEAP Summer Cooling Program.

Q45. What is the estimated impact of this low income proposal?

A45. Based upon prior experience with LIHEAP funding, NIPSCO estimates that 18,300 customers may receive benefits under the program. With a one-time $50 bill credit applied to June bills, NIPSCO estimates a total program cost of $915,000. A $0.20 flat monthly surcharge multiplied by 403,500 residential customers provides a total fund of $968,400, which will be available for the program. A summary of the impact and proposed charge is included in the table below.

Line		Low Income Program	Calculation (Line Nos.)
1	Estimated low income program recipients	18,300	
2	Annual benefit per low income recipient	$50	
3	Total low income program cost estimate	$915,000	1 x 2
4	Total residential customers	403,409	
5	Annual residential customer contribution (rounded)	$2.27	3 / 4
6	Monthly residential customer contribution (rounded)	$0.19	5 / 12 mos.
7	**Proposed monthly low income program charge**	**$0.20**	

<u>Summary of NIPSCO's Requested Tariff Relief</u>

Q46. Please summarize the key proposals regarding NIPSCO's Electric Tariff.

A46. As described herein as well as by Messrs. Westerhausen and Mays, NIPSCO is proposing a number of updates to its Electric Tariff.

Q47. Please describe NIPSCO's proposal to terminate the residential space heating rates.

A47. In Cause No. 44436, the Commission approved a revenue neutral, five-year transition plan to eliminate the residential space heating rates. Year 1 of the transition began January 1, 2015. Since the base rates for the impacted rate classes would change by operation of this case filing, it is reasonable to simplify and move forward with the elimination of the residential space heating rates at this time. NIPSCO Witness D. Joseph Mays explains NIPSCO's proposal in this case.

Q48. Is NIPSCO proposing any material changes to its Rider 675 – Interruptible Industrial Service or Rider 676 – Back-Up, Maintenance and Temporary Industrial Service Rider?

A48. No. As discussed above, NIPSCO is not proposing any material changes to the structure of Rider 675. However, based upon experience over the last few years, there are some miscellaneous tariff revisions to Riders 675 and 676 for purposes of clarifying terms and conditions of those services.

Q49. Although you are not proposing to materially change Rider 675, are the currently-effective demand credits in Rider 675 appropriate to continue?

A49. Yes. Under Option D, customers receive a $9.00 per kilowatt ("kW") per month credit; however a vast majority of customers are under Option C, which represents an $8.00 per kW per month credit. As approved by the Commission in NIPSCO's 30-Day Filing Cause No. 3321 on February 27, 2015, the value of the currently registered 377 MW is approximately $9.16 per kW per month. The equivalent annualized dollar value of a 220 MW simple cycle combustion turbine is approximately $24 million. Assuming $9.16 per kW per month remains constant, and a 377 MW simple cycle combustion turbine was used for the study; the resulting annualized dollar value would be approximately $41 million, which is in alignment with the current $38 million NIPSCO pays to customers subscribed under Rider 675. In addition, NIPSCO anticipates on a forward looking basis that the capacity received from current Rider 675 will be available through 2035 as detailed in NIPSCO's 2014 Integrated Resource Plan data assumptions.

Q50. Is NIPSCO proposing to re-open the process for customers desiring to elect service under Rider 675?

A50. No. The customers currently under Rider 675 have entered into long-term agreements for service under the Rider, and this has provided a level of certainty for NIPSCO and the participating customers, including meeting resource adequacy requirements mandated by MISO.

Q51. Please explain NIPSCO's proposed changes to its Rider 671 – Adjustment of Charges for Environmental Cost Recovery Mechanism ("ECRM") and Rider 673 – Adjustment of Charges for Environmental Expense Recovery Mechanism ("EERM").

A51. NIPSCO is proposing to consolidate the ECRM and EERM Riders into one set of factors and to set them on the same cycle for purposes of filing and recovery. Given the relationship between the projects contained in the ECRM and the expenses inside of the EERM, it is appropriate to consolidate the two into one set of factors. Moreover, it will provide the Commission and stakeholders a further opportunity to see any changes to ongoing environmental expenses by reviewing the eligible EERM expenses at each ECRM filing interval rather than just once a year.

Messrs. Isensee and Westerhausen both provide additional details on the proposed consolidation.

Q52. Please explain NIPSCO's proposed treatment of off-system sales in base rates and the impact to Rider 671 – Adjustment of Charges for Regional Transmission Organization ("RTO") tracker.

A52. As Mr. Isensee explains, NIPSCO is proposing to include in its base rates a credit amount of $4,741,390, which is equal to the Company's off-system sales margin in the test year. As NIPSCO Witness Daniel T. Williamson explains, NIPSCO will also flow through to customers via the RTO tracker 50% of any positive or negative variance to this amount. This symmetrical treatment above and below the amount in base rates is fair, and provides a reasonable incentive to NIPSCO to maximize the use of its generation facilities while also recognizing that it should not wholly bear the risk of any volatile and unpredictable market factors that render future off-system sales less than the amount included in base rates.

Q53. Please explain NIPSCO's proposed change to its Rules regarding its AMR Opt-Out Charge.

A53. Inside of its miscellaneous and non-recurring charges, NIPSCO is proposing to incorporate an opt-out charge for customers who refuse installation of an Automated Meter Reading ("AMR") upgrade to their electric meter to measure and report their usage. To date, 211 electric or combination customers (impacting 360 meters) have refused installation or otherwise not responded regarding the installation of the AMR electric meters. The opt-out charge will recover the incremental costs of continuing manual meter reads and will provide a market signal to customers choosing to have their meter(s) manually read. For the vast majority of customers that have not refused installation of this device, it is not appropriate for them to subsidize the marginal costs of maintaining manual meter reads for a small number of customers that refuse. This charge will send the appropriate signal to those customers as well as allocate a portion of the cost to them.

Only customers that refuse installation of the AMR device will be affected. The charge will consist of a monthly maintenance fee of $15 to recognize the cost of manually reading the meter. It should also be noted that the amount of $15 is a conservative calculation of this charge. This amount takes into consideration the efficiencies gained by meter readers as they become familiar with the revised routes. It accounts for the balance of urban/suburban and rural customers as the time required and the mileage driven to obtain manual readings in rural areas is much greater. And, it also reflects the use of the standard meter reader hourly pay rate rather than an overtime rate. The workpapers supporting the calculation of the AMR Opt-Out Charge are provided in response to MSFR 1-5-16(a)(3)(G).

Q54. Please describe NIPSCO's effort to streamline language in its electric tariff.

A54. Similar to the effort to clarify terms and conditions within certain Riders, Mr. Westerhausen discusses NIPSCO's comprehensive review of its existing tariff language to ensure that definitions are consistent across rates and to improve the ease of reading and understanding NIPSCO's tariff.

Q55. Is NIPSCO proposing any other tariff changes?

A55. Yes. As discussed above, NIPSCO is filing its changes in this proceeding based upon the currently-effective 600 series service structure framework. From that starting point, NIPSCO has proposed revisions to clarify the tariff or the operation of the currently-effective rate schedules. These revisions, in general, are designed to further align with the objectives noted above, eliminate ambiguity, and provide for a smoother operation between the Company and its customers based upon information learned since implementation of the 600 series structure with the 43969 Settlement.

Adjustments Made to Test Year Operating Results

Q56. Please describe the methodology used by NIPSCO to reset the demand-side management lost margin recovery.[14]

A56. NIPSCO has adjusted its usage determinants for energy efficiency measures installed through December 31, 2014, consistent with Evaluation, Measurement and Verification ("EM&V"). NIPSCO has also adjusted its usage upward for energy efficiency measures installed between January 1 and March 31, 2015. NIPSCO proposes to reset lost margins in its Demand Side Management Adjustment Mechanism ("DSMA") upon new, effective base rates in this proceeding to eliminate lost margins attributable to all energy efficiency measures installed prior to December 31, 2014. NIPSCO will reconcile lost margins inside of its DSMA for measures installed subsequent to December 31, 2014 consistent

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[14] For purposes of this testimony, NIPSCO uses "lost margin" synonymously with "lost revenue," as that term is used and defined in Ind. Code § 8-1-8.5-10.

with EM&V results when they are available and in the following DSMA filing. Ultimately, NIPSCO is seeking a neutral transition to lost margin recovery between the filing of this rate case and the operation of its DSMA filings.

This adjustment will reduce the amount of lost revenues recovered through the DSMA by approximately $18 million per year.

Q57. Please explain the adjustments made to test year billing determinants related to the inclusion of DSM measures installed up to and throughout the test year.

A57. To properly reflect the full impact of measures installed up through December 31, 2014, NIPSCO normalized both the kW and kilowatt-hour ("kWh") billing determinants from the test year to capture the annualized impact of measures installed throughout the test year. This is necessary to determine what test year kW and kWh would have been if all measures installed at December 31, 2014 were installed as of April 1, 2014, the first day of the test year. Additionally, NIPSCO also adjusted out the lost kWh and kW related to measures installed after December 31, 2014 as such measures will still be reflected and recovered through the DSMA. If these adjustments are not included, kWh and kW billing determinants would be overstated. Mr. Westerhausen describes this further in his testimony.

Q58. Is this consistent with the Commission's August 8, 2012 Order in Cause No. 44154 that approved NIPSCO's lost margin recovery methodology?

A58. Yes. In that Order, the Commission noted (p. 9) that at the conclusion of NIPSCO's next base rate case, "the margin calculation will be updated and the cumulative measure savings reset to zero as of the close of the test year." The reset methodology that I describe above meets this requirement while also recognizing the savings that have been the subject of EM&V, which is appropriate to use as a demarcation.

<u>**Appropriate Return on Used and Useful Assets**</u>

Q59. What is NIPSCO proposing in this proceeding regarding the opportunity to earn a fair return on the fair value of is property?

A59. NIPSCO is requesting the opportunity to earn an appropriate return on its used and useful assets by achieving, among other items, a return on equity that reflects current market conditions and risk, and an appropriate authorized NOI.

Q60. Please describe NIPSCO's development of its fair value rate base.

A60. NIPSCO developed its fair value rate base of approximately $5.7 billion by taking a weighted average of (i) the Replacement Cost New Less Depreciation ("RCNLD") value of its electric utility assets (~$8.1 billion) plus its prepaid pension asset, certain regulatory assets, materials, supplies, and production fuel amounts (~$386.5 million) and (ii) the original cost less depreciation ("Original Cost") of NIPSCO's utility property (~$3.4 billion). NIPSCO Witness Paul R. Moul supports this calculation. NIPSCO Witness Ann E. Bulkley describes the valuation study performed to determine the RCNLD.

The Commission authorized the use of RCNLD to establish fair value rate base in 2010.[15] In the present case, NIPSCO is proposing to calculate the fair value of its rate base using an even more conservative method. The Company is proposing to use a weighted average of RCNLD and Original Cost, which will yield a fair value less than that which would have resulted from using only RCNLD.

Q61. Does NIPSCO adopt Mr. Moul's determination of the fair value of NIPSCO's rate base in this proceeding?

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15 Cause No. 43624, Westfield Gas

A61. Yes. NIPSCO proposes ~$5.7 billion as the fair value of its rate base.

Q62. Please describe NIPSCO's development of the fair rate of return.

A62. Consistent with the Commission's March 10, 2010 Order in Cause No. 43624 ("Westfield Order"), NIPSCO reduced its cost of common equity by the expected future inflation rate before calculating the Company's weighted cost of capital. Mr. Moul describes this calculation.

Q63. Does NIPSCO adopt Mr. Moul's determination of the fair rate of return on NIPSCO's fair value rate base?

A63. Yes. NIPSCO adopts Mr. Moul's determination of 5.95% as the fair rate of return on NIPSCO's fair value rate base.

Q64. What is the fair return determination that NIPSCO is seeking in this case?

A64. NIPSCO requests a fair return determination of approximately $340.4 million, which is equal to Mr. Moul's recommended fair rate of return of 5.95% multiplied by NIPSCO's fair value rate base of ~$5.7 billion. However, NIPSCO is proposing base rates that are designed to earn a more conservative NOI of approximately $234.5 million.

Q65. Is NIPSCO's proposed fair return reasonable and just?

A65. Yes. The Indiana Legislature has made the policy decision that "fair value" encompasses more than just the original cost or net book value of a utility's property. Indiana Code §8-1-2-6(a) provides:

> The commission shall value all property of every public utility actually used and useful for the convenience of the public at its fair value, giving such consideration as it deems appropriate in each case to *all bases of valuation* which may be presented or which the commission is authorized to consider by the following provisions of this section. As one of the elements in such valuation the commission shall give weight to the reasonable cost of bringing the property to its then state of efficiency. In making such valuation, the commission may avail itself of any information in possession of the department of local government finance or of any local authorities. . .

The Commission has acknowledged that its fair return determination must give "actual effect to Indiana's fair value statute." Westfield Order at 29. "[T]he Commission must find the current fair value of Petitioner's used and useful property dedicated to service of the public in Indiana, and give actual effect to that fair value finding in determining allowed return." *Id.*

Fair value is the true current worth of a utility's property. The Commission has approved RCNLD as an appropriate method to determine fair value because Ind. Code § 8-1-2-6(b) explicitly approves of that method and because Indiana Courts have instructed the Commission to consider RCNLD in determining fair value rate base. *Id.* at 16. Ms. Bulkley determined the RCNLD of NIPSCO's electric utility plant, and demonstrates that NIPSCO's property is worth more than its net book value. Mr. Moul calculated the fair value rate base using the weighted average of (i) RCNLD value of NIPSCO's electric utility assets plus its materials, supplies, and production fuel amounts and (ii) Original Cost of NIPSCO's utility property. This weighted average approach is a conservative calculation of the fair value of NIPSCO's rate base compared to using the RCNLD standing alone.

Moreover, NIPSCO's return on equity on the fair value rate base, if the NOI is limited to ~$234.5 million, would equate to 4.76%, or an overall rate of return of 4.09%. This rate of return on equity is less than the long-term debt cost rate in NIPSCO's capital structure, as supported by NIPSCO Witness Vincent V. Rea. A return on equity at this level is not consistent with finance principles, and NIPSCO should be afforded the opportunity to earn a fair return.

Q66. Are the differences between a traditional fair value approach to ratemaking and an "original cost" approach substantive, or are they merely two alternatives that should result in the same answer?

A66. Fair return on fair value may or may not produce results similar to a return on net original cost. Fair return on fair value considers the appropriate return from the "outside in" versus original cost ratemaking which is heavily based on "inside out." The fair value of a utility's assets should consider external factors such as RCNLD and the effectiveness of management in developing and operating the system to meet the needs of customers while providing safe and reliable services. With the headwinds faced by our electric industry, NIPSCO's risk profile given its large proportion of load in the hands of a few industrial customers, and continued capital investment needs to support modern infrastructure, it is appropriate to utilize a fair return on the fair value of NIPSCO's property for purposes of establishing the authorized NOI in this case. This is contrasted by original cost ratemaking with its focus on historical cost and accounting depreciation which may have no relationship to the external environment.

There is substantial management discretion in an energy utility, as there is in all businesses, as to how people, physical assets and contract property rights are to be deployed. Management can add value and management can lose value as a result of decisions made over time. Energy utility ratemaking should not be reduced to a formula where one narrowly defined range of returns on the book value of equity fits all players. Such a practice is a disincentive to efficiency that covers up poor decision making and provides no owner benefit for decisions that add value to the business.

For example and especially in light of continuing and expanding environmental regulations and compliance requirements, coal-fired electric production assets are under pressure. Increasing production costs for coal units resulting from environmental expenditures provide for a less competitive position in the marketplace. It is an appropriate signal for management to have an opportunity to earn a fair return on fair value to realize the benefits of addressing these pressures through efficiency gains or other process improvement measures.

Limiting a utility's operating income to a formula that is focused on the original cost of a utility's investment in property sends dangerous and inefficient signals and is certainly not the favored approach under Indiana law. Original cost ratemaking, without consideration of fair value, over-emphasizes historical fortune or misfortune, places no value on management's efficiency in capital deployment and operations, does not properly account for the attraction of future capital, and lacks basic precepts of fairness. Under such a formulaic approach, the only way for a utility to increase its earnings and the value it delivers to its investors over time is to add more property at an increasingly higher original cost. In the absence of capital expenditures, making its existing property more efficient or more valuable will not result in higher earnings because original cost methodologies do not consider these matters. In addition, adding more property at higher original cost incents the utility to encourage growth in demand to justify the new supply. This is not consistent with energy efficiency goals.

A regulatory system that allows a utility to earn a fair return on the fair value of its property, however, provides an appropriate signal with respect to efficiency because the fair value of a utility's property is different from its original book value, and one of the principal reasons for the difference lies in the efficiency with which the property has been acquired, deployed, operated and maintained. In short, a utility's authorized operating income could be increased or decreased irrespective of adding more units of property because changes in efficiency or operations could increase or decrease the fair value of its property.

Q67. Is NIPSCO using a revenue requirement that includes the fair return of approximately $340.4 million for the purpose of setting rates in this case?

A67. No. NIPSCO's proposed revenue requirement for purposes of setting rates includes a more conservative NOI of ~$234.5 million, which is based on Mr. Rea's weighted cost of capital calculation of 6.82% multiplied by the original cost rate base of ~$3.4 billion.

Q68. Why has NIPSCO proposed a revenue requirement and related rates that result in a return that is substantially less than the NOI it can support?

A68. The primary reason that NIPSCO proposes a return that is substantially lower than the fair return based on the fair value of its rate base is the desire to make changes to customer rates on a gradual basis. NIPSCO is seeking a number of changes that will impact customer rates in this proceeding, including certain changes in rate design intended to move closer to actual fixed-variable cost incurrence. Layering a large increase in revenue requirement on top of a rate design shift could be confusing and overly burdensome to many customers. However, NIPSCO is requesting that its authorized NOI allow it an opportunity to earn a return consistent with a fair return on its fair value rate base.

Q69. Why is NIPSCO requesting an authorized NOI that is higher than what its proposed rates will produce?

A69. NIPSCO is requesting an authorized NOI greater than its proposed rates will produce in order to give (1) its investors the opportunity to earn a fair return on the fair value of the capital they have invested and (2) its customers the benefit of lower rates based on original cost. At the rates proposed in this proceeding, the Company's investors will not be able to earn a fair return on the fair value of their investment. It is only through growth in customer base and customer demand that investors will have the opportunity to earn this fair return. However, if the Commission does not set NIPSCO's authorized NOI at an amount necessary to provide these investors the opportunity to earn a fair return, paradoxically, the Company will have to refund to its customers earnings that the investors should be entitled to retain. Moreover, to the extent NIPSCO is not afforded an opportunity to timely recover its costs through other mechanisms, this proposal provides an opportunity to earn a fair return on the fair value of its investment.

Under Indiana law, utility customers have the right to just and reasonable rates and investors have the right to the opportunity to earn a fair return on the fair value of their investment. NIPSCO's request to use original cost ratemaking to set base rates and to use a fair value return to determine authorized NOI reasonably balances these rights in this filing, given the other customer class rate changes being proposed.

Q70. Does this complete your prefiled direct testimony?

A70. Yes.

VERIFICATION

I, Frank A. Shambo, Vice President, Regulatory and Legislative Affairs for Northern Indiana Public Service Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief

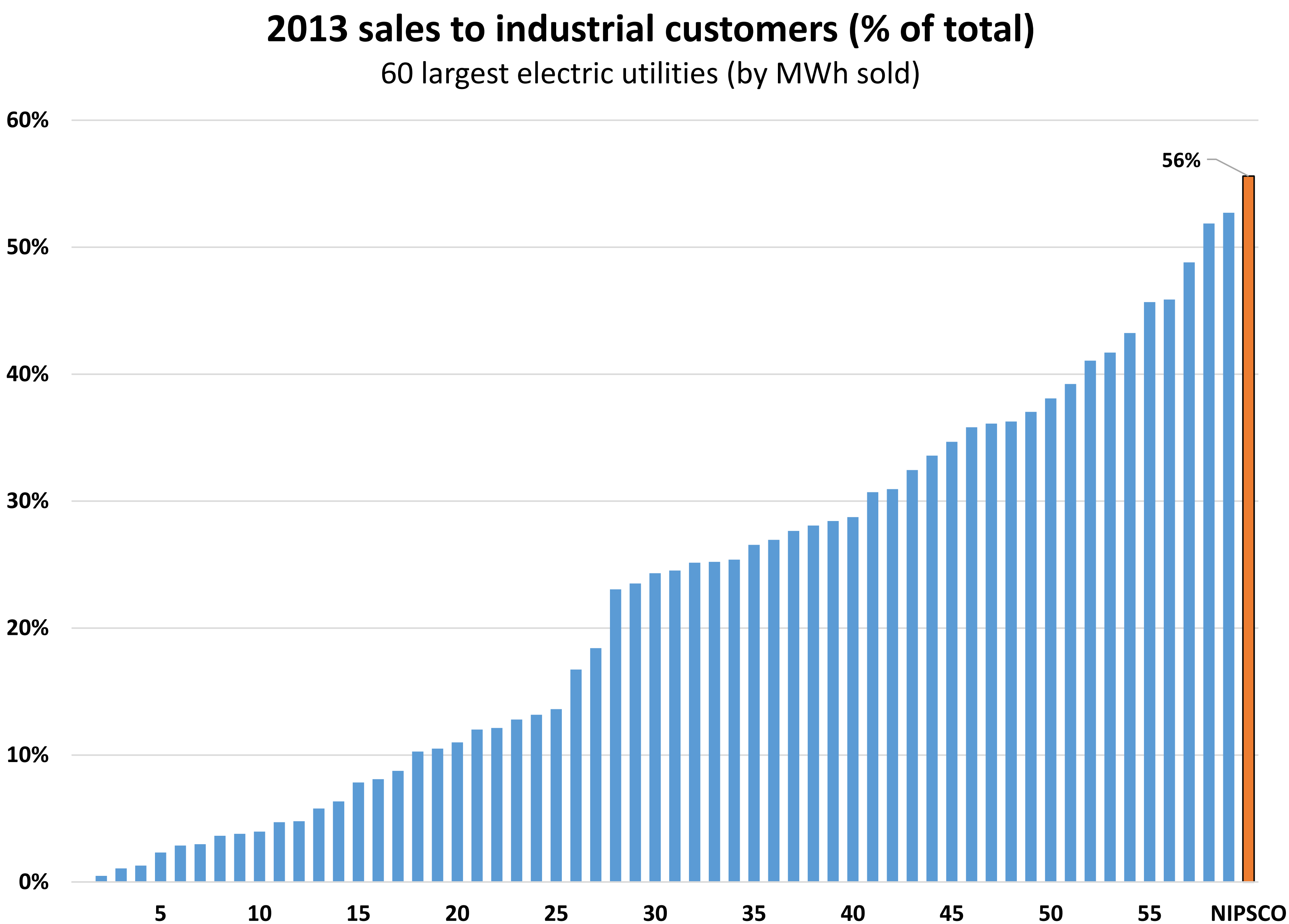
Frank A. Shambo

Date: October 1, 2015

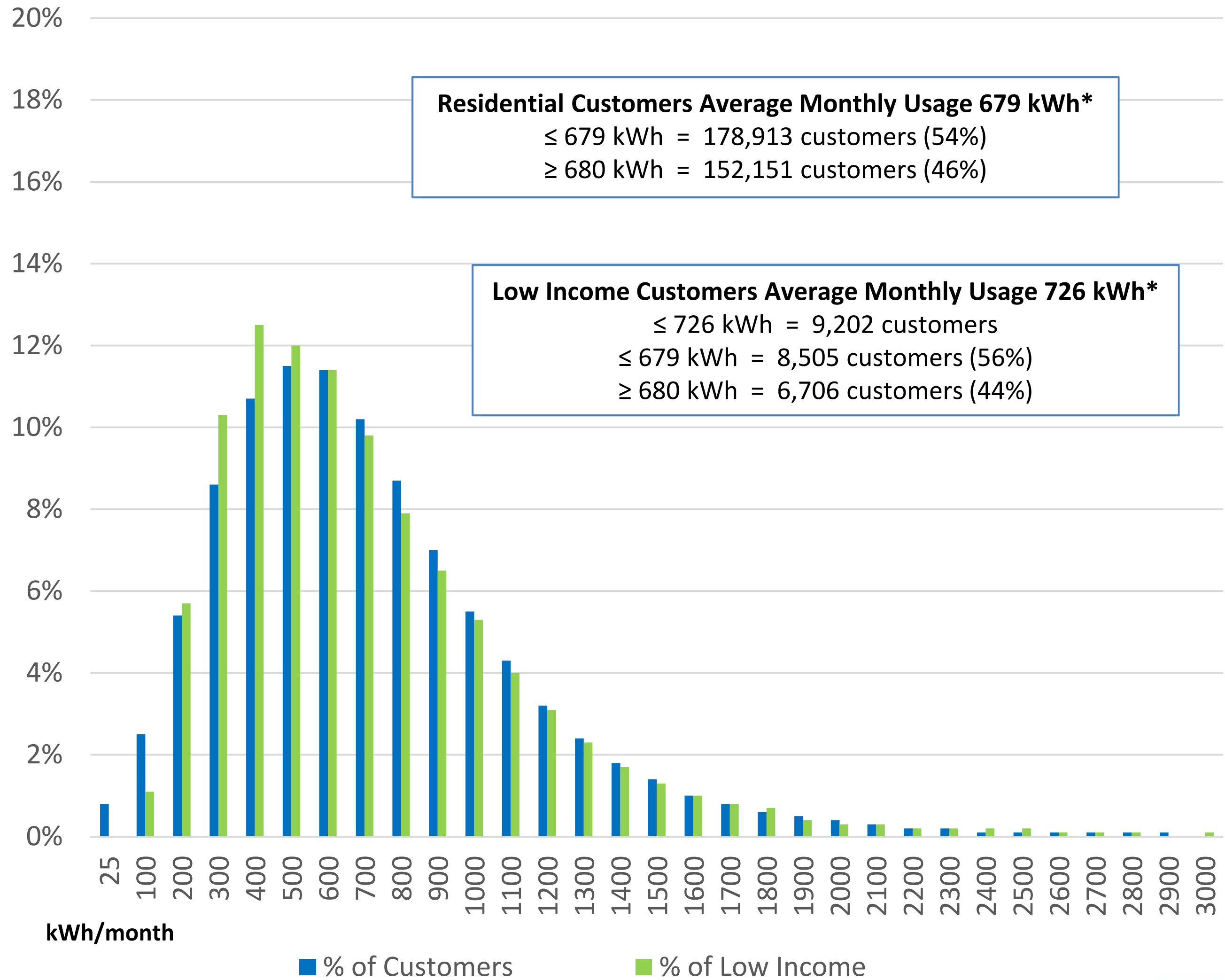
Petitioner's Exhibit No. 2
Attachment 2-A
Cause No. 44688

Verified Petition
[Not Duplicated Herein]

Petitioner's Exhibit No. 2
Attachment 2-B
Cause No. 44688



Residential Customer Distribution



* Actual usage of customers with 12 billing months of registered energy consumption above 0 kWh

NIPSCO