
VERIFIED DIRECT TESTIMONY OF KEVIN J. BLISSMER

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

A1. My name is Kevin J. Blissmer. My business address is 801 E. 86th Avenue, Merrillville, Indiana 46410. I am Manager of Regulatory for NiSource Corporate Services Company.

Q2. On whose behalf are you submitting this direct testimony?

A2. I am submitting this testimony on behalf of Northern Indiana Public Service Company LLC ("NIPSCO" or "Company").

Q3. Please describe your educational and employment background.

A3. I graduated from Purdue University with a Bachelor of Science Degree majoring in both Accounting and Finance. I was employed at Universal Access, a small public telecommunications company based in Chicago, Illinois for three years, where I progressed in my career to Assistant Controller before leaving to join NiSource Inc. ("NiSource"). I joined NiSource in 2003 as the Manager of SEC Reporting and Research until 2010, after which I held roles as Manager of Accounting Research and Manager of Corporate Finance. I joined NIPSCO's Rates and Regulatory Finance Department in 2014 as the Manager of Regulatory Accounting, and, on November 1, 2017, I accepted my current position as Manager of Regulatory. I am a Registered Certified Public Accountant ("CPA") in the State of Illinois.

Q4. What are your responsibilities as Manager of Regulatory?

A4. As Manager of Regulatory, I am responsible for the preparation and coordination of NIPSCO's Electric Transmission, Distribution and Storage System Improvement Charge ("TDSIC") filings, Green Power Rider annual filings (Cause No. 44198-GPR-X), Electric Demand Side Management filings (Cause No. 43618-DSM-X), and Regional Transmission Organization Adjustment semi-annual filings (Cause No. 44156-RTO-XX). I am also responsible for the preparation and coordination of NIPSCO's annual Attachments O, GG, and MM postings to the Midcontinent Independent System Operator, Inc. ("MISO"). I also support the preparation and coordination of Columbia Gas of Maryland regulatory filings.

Q5. What is the purpose of your testimony?

A5. The purpose of my testimony is to (1) explain the schedules supporting the proposed RTO Adjustment factors in this proceeding; (2) describe the demand and energy allocators; (3) explain the impact of customer migrations, if any; (4) provide NIPSCO's current Attachments O, GG, and MM; and (5) provide the current forecasted amount of Schedule 26-A revenues for the period November 2020 through April 2021, which is the forecasted period in this case.

Q6. Please provide a background on the RTO Adjustment.

A6. The Commission's August 25, 2010 Final Order in Cause No. 43526 ("43526 Order") found that NIPSCO's MISO non-fuel costs and revenues and off-system sales ("OSS") sharing should be included in one mechanism designated as the RTO Adjustment.[1] The Commission's December 21, 2011 Final Order in Cause No. 43969 ("43969 Order") authorized the implementation of the RTO Adjustment from Cause No. 43526 by approving NIPSCO's Rider 671 – Adjustment of Charges for Regional Transmission Organization and NIPSCO's Appendix C – Regional Transmission Organization Adjustment Factor. The 43969 Order specified

[1] 43526 Order at 93-94.

that the RTO Adjustment will be a semi-annual mechanism coordinated with the Fuel Adjustment Clause ("FAC") audit process.[2]

The Commission's July 18, 2016 Order in Cause No. 44688 ("44688 Order") specified that the RTO Adjustment will recover MISO non-fuel costs and revenues that exceed $16,585,108 annually or $8,292,554 semi-annually (the amount of MISO non-fuel credits and charges included in base rates). The 44688 Order also reset the RTO benchmark to recover or pass back any amounts above or below this amount through the RTO Adjustment and reset the OSS margin credit to base rates to reflect the level of OSS included in the test year of $4,741,390. The 44688 Order also directed NIPSCO to flow through the RTO Tracker 100% of its OSS margins, below (down to zero) or above $4,741,390 annually (the level built into base rates).[3]

The Commission's December 4, 2019 Order in Cause No. 45159 ("45159 Order") approved NIPSCO's Verified Petition requesting authority to modify its rates and charges for electric utility service. As part of that approval effective January 2020 with Step 1 base rates, the Commission,

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[2] 43969 Order at 70.
[3] 44688 Order at 88.

among other things, approved NIPSCO's Rider 871 – Adjustment of Charges for Regional Transmission Organization and NIPSCO's Appendix C – Regional Transmission Organization Adjustment Factor, including approval to: (1) remove MISO charges and credits previously included in base rates and collect 100% of MISO charges that are not included in the FAC through the RTO; (2) remove positive or negative OSS margins previously included in base rates and flow back 100% of any OSS margins net of expenses through the RTO; (3) remove all back-up and maintenance margins[4] currently included in base rates and pass back 100% of such margins net of expenses through the RTO; (4) change the allocation methodology to the 4 Coincident Peak allocation set out in Corrected Rate 831 Implementation Agreement Exhibit A to the approved Rate 831 Settlement;[5] and (5) remove the Utility Receipts Tax ("URT").

Q7. Please summarize the relief NIPSCO is requesting in this proceeding.

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[4] These revenues are collected under Rider 876 - Back-Up, Maintenance, and Temporary Services ("BUM").

[5] Stipulation and Settlement Agreement on Rate 831 Implementation by and among NIPSCO, NIPSCO Industrial Group, NLMK Indiana, and United States Steel Corporation, filed in Cause No. 45159 (as revised June 7, 2019) (the "Rate 831 Settlement").

A7. NIPSCO requests approval of revised RTO Adjustment factors to be applicable and made effective for bills rendered during the billing cycles of November 2020 through April 2021 or until replaced by different factors approved in a subsequent filing.

In this proceeding, NIPSCO is seeking to: (1) recover its MISO non-fuel costs, net of revenues, estimated for the billing cycles of November 2020 through April 2021, (2) provide actual MISO non-fuel costs for the period January through June 2020 and refund the variance between these actual RTO costs incurred compared to revenue collected for those months, and (3) report OSS and BUM margins incurred for the period January through June 2020. OSS and BUM margins from this RTO-18 filing will be compiled with OSS and BUM margins for the period July through December 2020 (to be reported in RTO-19) for the purposes of calculating any OSS and BUM margins (net of expenses) that may be flowed back through the RTO in accordance with the 45159 Order. Therefore, the annual OSS and BUM margins to be returned to customers in this proceeding is $0 [Schedule 3, Line 17].

Q8. Are you sponsoring any attachments to your direct testimony?

A8. Yes. I am sponsoring Attachments 1-A through 1-D, which were prepared by me or under my direction and supervision.

Q9. Please explain Attachment 1-A.

A9. Attachment 1-A is the Verified Petition filed in this Cause, including Attachments A, B, and C attached thereto.

Q10. Please explain Attachment 1-A, Attachment A.

A10. Attachment 1-A, Attachment A includes Schedules 1 through 6. Schedule 1 shows the allocation of all costs based on energy or demand to derive the proposed RTO Adjustment factors for the billing period. Schedule 2 shows the determination of the MISO non-fuel costs, net of revenues, for the six month estimate period. Schedule 3 shows the actual OSS and BUM margins per month for January through June 2020 and the determination of actual annual OSS and BUM margins to be returned in this proceeding [Schedule 3, Line 14].[6] Schedule 4 shows the reconciliation of the actual costs and revenues. Schedule 5 shows the detail of the actual costs included in the

[6] As noted above, beginning January 1, 2020, all OSS and BUM margins (net of expenses) are being returned to NIPSCO's customers as no OSS or BUM margin amounts are included in base rates. The amount of OSS and BUM margins for 2020 will be addressed in RTO-19.

reconciliation. Schedule 6 shows the details of the variance and OSS margins included in the reconciliation.

Q11. What charges or credits are included for recovery as "Other" or "Miscellaneous" on Schedule 5 in this filing?

A11. There is a $337 charge included for recovery in "Other Miscellaneous Transmission Schedules/Amounts," on Schedule 5, Page 2, Line 21. NIPSCO Witness Weiss describes the charge in his testimony.

Q12. How did NIPSCO calculate the total amount of RTO charges and credits included in this proceeding?

A12. Schedule 1, Lines 1 through 6 of <u>Attachment 1-A</u>, Attachment A show how the total charges of $16,135,712 were calculated. The amount of prior period variance included in this proceeding is a credit for an over-collection of $645,735. NIPSCO Witness Weiss describes the $1,782,182 (over-collection) variance attributable between actual and estimated costs. The remaining $1,136,447 (under-collection) variance is due to volumetric and timing differences.

Q13. How did NIPSCO calculate the RTO Adjustment factors proposed in this proceeding?

A13. Schedule 1 includes the demand-allocated and energy-allocated MISO non-fuel costs and credits from Schedule 2, the OSS and BUM margins amount from Schedule 3 (if applicable), and the prior period variance from Schedule 4. The forecasted MISO non-fuel costs and credits from Schedule 2 are allocated to each rate class using the allocators approved in the 45159 Order adjusted for Rate 831 adjustments and the impact of significant migrations of customers to different rate classes. OSS and BUM margins, if applicable, are allocated to each rate class using the allocators in effect during the respective month of collection. The prior period variance is allocated to each rate class using the allocators in effect during the 6-month reconciliation period. These allocated costs by rate are then divided by the forecasted sales for the billing period to determine the individual billing components which comprise the RTO Adjustment factor for each rate (Schedule 1, Column (p)). Attachment 1-A, Attachment C shows the RTO Adjustment factors proposed to be effective for bills rendered during the billing cycles of November 2020 through April 2021, which begins October 29, 2020.

Q14. Please describe the demand and energy allocators used to calculate the demand- and energy-related costs by rate code.

A14. The demand and energy allocators being utilized in this filing were approved in the Commission's 45159 Order (at 158-159), whereby the demand allocators are based upon forecasted customer revenue and the energy allocators are based upon forecasted volumes at the source for the forecasted test year ended December 31, 2019.

Q15. Is NIPSCO proposing any adjustments to its demand allocators in this filing?

A15. Yes. As shown in Attachment 1-A, Attachment B, NIPSCO has adjusted its demand allocation percentages to reflect the migration of customers amongst Rates 824 and 826 and for current contractual demand under Rate 831. These adjustments are appropriate in order to prevent any unintended consequences of the migration of customers to different rate classes and to properly allocate their share of RTO charges/credits, as well as to properly allocate RTO charges/credits in association with current contractual demand volumes for Rate 831 customers.

Q16. Is NIPSCO proposing any adjustments to its energy allocators in this filing?

A16. Yes. As shown in <u>Attachment 1-A</u>, Attachment B, NIPSCO has adjusted its energy allocation percentages to reflect the migration of customers amongst Rates 824 and 826, and for current contractual agreements under Rate 831. These adjustments are appropriate in order to prevent any unintended consequences of the migration of customers to different rate classes and to properly allocate their share of RTO charges/credits, as well as to properly allocate RTO charges/credits in association with current contractual energy volumes for Rate 831 customers.

Q17. Please explain <u>Attachment 1-A</u>, Attachment C.

A17. <u>Attachment 1-A</u>, Attachment C is Petitioner's Appendix C – Regional Transmission Organization Adjustment Factor (Second Revised Sheet No. 204) showing the RTO Adjustment factors proposed to be effective for bills rendered during the billing cycles November 2020 through April 2021, which begins October 29, 2020.

Q18. What effect will the proposed RTO Adjustment factors have on an average residential customer?

A18. The proposed factor will add $2.34 to a 700 kWh residential bill, which was the average monthly residential bill during the test year in NIPSCO's last rate case. This will be an increase of $0.51 compared to the factor currently in effect.

The proposed factor will add $3.34 to a 1,000 kWh residential bill, which is $0.72 more than the factor currently in effect.

Q19. Please identify <u>Attachment 1-B</u>.

A19. <u>Attachment 1-B</u> is NIPSCO's most current Attachment O effective on July 1, 2020. Attachment O, which is submitted by every Transmission Owner in MISO, is a rate formula that sets forth the method for calculating and collecting charges and distributing revenues associated with those charges for all applicable transmission assets under MISO's functional control. In general, the collection of charges and distribution of revenues associated with this attachment is accomplished through Schedules 7, 8, and 9 for all Transmission Owners. In RTO-1, NIPSCO agreed to provide this information.

Q20. Please identify <u>Attachment 1-C</u>.

A20. Attachment 1-C is NIPSCO's most current Attachment GG effective on July 1, 2020. Attachment GG is only applicable to certain projects designated as eligible for cost sharing by MISO. Attachment GG sets forth the method for calculating and collecting the charges associated with network upgrades eligible for cost sharing and for distributing the revenues associated with such charges. The collection of charges and distribution of revenues associated with these projects is accomplished through Schedule 26. In RTO-1, NIPSCO agreed to provide this information.

Q21. Please identify Attachment 1-D.

A21. Attachment 1-D is NIPSCO's most current Attachment MM effective on July 1, 2020. Attachment MM is only applicable to projects which are declared to be Multi Value Projects ("MVP") eligible by MISO. Attachment MM sets forth the method for calculating and collecting the charges associated with MVP eligible network upgrades and for distributing the revenues associated with such charges. The collection of charges and distribution of revenues associated with these projects is accomplished through Schedule 26-A. In RTO-1, NIPSCO agreed to provide this information.

Q22. Please identify the amount of MISO Schedule 26-A revenues NIPSCO currently forecasts for the period November 2020 through April 2021.

A22. Based on NIPSCO's current forward looking formula rate structure, which uses NIPSCO forecast information and is trued up in a future period using FERC Form 1, NIPSCO projects Schedule 26-A revenues of approximately $32.6 million for the period November 2020 through April 2021.

Q23. Does this conclude your prepared direct testimony?

A23. Yes.

VERIFICATION

I, Kevin J. Blissmer, Manager of Regulatory of NiSource Corporate Services Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Kevin Blissmer

Kevin J. Blissmer

Dated: August 17, 2020

Attachment 1-A

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC FOR APPROVAL OF REGIONAL TRANSMISSION ORGANIZATION ADJUSTMENT FACTORS TO BE APPLICABLE DURING THE BILLING CYCLES OF NOVEMBER 2020 THROUGH APRIL 2021 PURSUANT TO IND. CODE § 8-1-2-42.	**)))))))**	**CAUSE NO. 44156 RTO 18**

VERIFIED PETITION

Northern Indiana Public Service Company LLC ("NIPSCO" or "Petitioner") petitions the Indiana Utility Regulatory Commission ("Commission") for approval of regional transmission organization adjustment ("RTO Adjustment") factors to be applicable for bills rendered during the billing cycles of November 2020 through April 2021, or until replaced by different RTO Adjustment factors that are approved in a subsequent filing, pursuant to Ind. Code § 8-1-2-42. In accordance with 170 IAC 1-1.1-8 and 1-1.1-9, Petitioner submits the following information in support of this petition.

<u>Petitioner's Corporate and Regulated Status</u>

1. NIPSCO is a limited liability company organized and existing under the laws of the State of Indiana with its principal office and place of business at 801 East 86th Avenue, Merrillville, Indiana. Petitioner renders electric public

utility service in the State of Indiana and owns, operates, manages and controls, among other things, plant and equipment within the State of Indiana used for the generation, transmission, distribution and furnishing of such service to the public. Petitioner is a "public utility" under Ind. Code § 8-1-2-1 and is subject to the jurisdiction of this Commission in the manner and to the extent provided by the Public Service Commission Act, as amended, and other pertinent laws of the State of Indiana.

Petitioner's Operations

2. Petitioner is a member of the Midcontinent Independent System Operator, Inc. ("MISO"), a FERC-approved regional transmission organization. Petitioner participates in the various markets administered by MISO. As a participant in the MISO markets, NIPSCO is subject to various charges and credits assessed by MISO.

Background

3. The Commission's August 25, 2010 Final Order in Cause No. 43526 ("43526 Order") found that NIPSCO's MISO non-fuel costs and revenues and off-system sales ("OSS") sharing should be included in one mechanism designated as the RTO Adjustment. 43526 Order at 93-94. The Commission's December 21, 2011 Final Order in Cause No. 43969 ("43969 Order") authorized the implementation of the RTO Adjustment from Cause No. 43526 by approving NIPSCO's Rider 671 –

Adjustment of Charges for Regional Transmission Organization and NIPSCO's Appendix C – Regional Transmission Organization Adjustment Factor. 43969 Order at 70. The 43969 Order specified that the RTO Adjustment will be a semi-annual mechanism coordinated with the FAC audit process. *Id.*

4. The Commission's July 18, 2016 Order in Cause No. 44688 ("44688 Order") specified that the RTO Adjustment will recover MISO non-fuel costs and revenues that exceed $16,585,108 annually or $8,292,554 semi-annually (the amount of MISO non-fuel credits and charges included in base rates). The 44688 Order also reset the RTO benchmark to recover or pass back any amounts above or below this amount through the RTO Adjustment and reset the OSS margin credit to base rates to reflect the level of OSS included in the test year of $4,741,390. The 44688 Order also directed NIPSCO to flow through the RTO Tracker 100% of its OSS margins, below (down to zero) or above $4,741,390 annually (the level built into base rates).

5. The Commission's December 4, 2019 Order in Cause No. 45159 ("45159 Order") approved, among other things, NIPSCO's Rider 871 – Adjustment of Charges for Regional Transmission Organization and NIPSCO's Appendix C – Regional Transmission Organization Adjustment Factor, including approval to (1) remove MISO charges and credits previously included in base rates and collect

100% of MISO charges that are not included in the FAC through the RTO; (2) remove positive or negative OSS margins currently included in base rates and flow back 100% of any OSS margins net of expenses through the RTO; (3) remove all back-up and maintenance margins previously included in base rates and pass back 100% of back-up, maintenance, and temporary services[1]margins net of expenses through the RTO; (4) change the allocation methodology to the 4 Coincident Peak allocation set out in Corrected Rate 831 Implementation Agreement Exhibit A to the approved Rate 831 Settlement;[2] and (5) remove the Utility Receipts Tax. The 45159 Order became effective January 1, 2020 with the implementation of Step 1 rates.

Relief Sought by Petitioner

6. In this proceeding, NIPSCO requests Commission approval of RTO Adjustment factors to be applicable and made effective for bills rendered by NIPSCO during the billing cycles of November 2020 through April 2021 or until replaced by different factors approved in a subsequent filing pursuant to provisions of the Public Service Commission Act, as amended.

7. The proposed RTO Adjustment factors are calculated based on

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1 BUM refers to Back-Up, Maintenance, and Temporary Services under Rider 876.

2 Stipulation and Settlement Agreement on Rate 831 Implementation by and among NIPSCO, NIPSCO Industrial Group, NLMK Indiana, and United States Steel Corporation, filed in Cause No. 45159 (as revised June 7, 2019) (the "Rate 831 Settlement").

estimated costs, flow back of 100% of any OSS and BUM margins net of expenses (as authorized in Cause No. 45159), energy and demand allocators, and forecasted usage for the period of November 2020 through April 2021. The proposed RTO Adjustment factors include reconciliations for the period January through June 2020. The data supporting the RTO Adjustment factors proposed herein is attached hereto as Attachment A.

8. The 45159 Order set forth the demand and energy allocators for the RTO Adjustment. NIPSCO has adjusted its demand and energy allocation percentages to reflect Rate 831 adjustments and the impact of significant migration of customers to different rate classes. The demand and energy allocators are shown in Attachment B.

9. Petitioner's total costs to be recovered during the billing cycles of November 2020 through April 2021 are shown on Attachment A, Schedule 1.

10. A clean and redlined version of Petitioner's Appendix C – Regional Transmission Organization Adjustment Factor (Second Revised Sheet No. 204), reflecting the RTO Adjustment factors proposed herein is attached hereto as Attachment C.

Procedural Matters

11. The books and records of Petitioner supporting such data,

calculation, and allegations are available for inspection and review by the Office of Utility Consumer Counselor and this Commission.

12. The RTO Adjustment factors will be applied to bills rendered by Petitioner during the billing cycles of November 2020 through April 2021, which begins October 29, 2020. To accommodate this billing date, NIPSCO respectfully requests that the Commission hold a hearing on or before October 12, 2020 and issue an order in this matter by October 28, 2020.

13. In its April 25, 2012 Order in Cause No. 44156-RTO-1, the Commission approved the following proposed procedural schedule for subsequent RTO Adjustment proceedings which is consistent with NIPSCO's FAC audit process:

> (a) Petitioner will file its Case-in-Chief (including a verified petition, proposed tariff revisions and supporting testimony) and provide the OUCC and any Intervenors with copies of all supporting workpapers no less than seventy-five (75) days before the effective date of the proposed RTO factors. Petitioner's Case-in-Chief will not be considered complete until all items listed above are filed (or, in the case of workpapers, submitted).
>
> (b) The OUCC and any Intervenors will file their respective Cases-in-Chief approximately 45 days after Petitioner files its completed Case-in-Chief.
>
> (c) Petitioner will file its rebuttal testimony (if any) no less than five (5) days prior to the evidentiary hearing.
>
> (d) Petitioner will make its staff reasonably available to the

OUCC and any Intervenors to facilitate an informal discovery process for its RTO filings. Any response or objection to a formal discovery request should be made within ten (10) calendar days of the receipt of such request, and the parties will utilize electronic discovery.

With respect to this proceeding, the procedural schedule is as follows:

NIPSCO filed Petition and Case-In-Chief	August 17, 2020
OUCC / Intervenors Filings	October 1, 2020
NIPSCO Rebuttal	October 5, 2020
Evidentiary Hearing	October 12, 2020
Order	October 28 2020

Applicable Law

14. Petitioner considers the provisions of the Public Service Commission Act, as amended, including Ind. Code §§ 8-1-1-8 and 8-1-2-4, 10, 12, 38, 39, 42, 68 and 71 to be applicable to the subject matter of this Petition and believes that such traditional statutes provide the Commission authority to approve the requested relief.

Petitioner's Counsel

15. The names and addresses of persons authorized to accept service of papers in this proceeding are:

Counsel of Record:	**With a copy to:**
Bryan M. Likins (No. 29996-49)	Cynthia C. Jackson
NiSource Corporate Services - Legal	Northern Indiana Public Service Company LLC
150 W. Market Street, Suite 600	150 W. Market Street, Suite 600
Indianapolis, Indiana 46204	Indianapolis, Indiana 46204
Phone: (317) 684-4922	Phone: (317) 684-4915
Fax: (317) 684-4918	Fax: (317) 684-4918
Email: blikins@nisource.com	Email: ccjackson@nisource.com

WHEREFORE, Northern Indiana Public Service Company LLC respectfully requests that the Commission promptly publish notice, make such other investigation, and hold such hearings as are necessary or advisable on or before October 12, 2020 in this Cause and, thereafter, make and enter an order in this Cause by October 28, 2020:

(a) Authorizing and approving the RTO Adjustment factors set forth in Attachment A, Schedule 1 to this Petition to become effective for bills rendered by NIPSCO during the billing cycles of November 2020 through April 2021 or until replaced by different RTO Adjustment factors that are approved in a subsequent filing;

(b) Approving Petitioner's Appendix C – Regional Transmission Organization Adjustment Factor set forth in Attachment C to this Petition, which contains the RTO Adjustment factors to become effective for bills rendered by NIPSCO during the billing cycles of November 2020 through

April 2021, which begins October 29, 2020; and

(c) Making such other and further findings and orders in the premises as the Commission may deem appropriate and proper.

Dated this 17th day of August, 2020.

Northern Indiana Public Service Company LLC

Erin E. Whitehead

Erin E. Whitehead
Vice President
Regulatory and Major Accounts

Verification

I affirm under penalties for perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

Dated: August 17, 2020.

Erin E. Whitehead

Erin E. Whitehead
Vice President
Regulatory and Major Accounts

Bryan M. Likins (No. 29996-49)
NiSource Corporate Services - Legal
150 West Market Street, Suite 600
Indianapolis, Indiana 46204
Phone: (317) 684-4922
Fax: (317) 684-4918
Email: blikins@nisource.com

Attorney for Petitioner
Northern Indiana Public Service Company LLC

CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by email transmission upon the following:

Randall C. Helmen
Lorraine Hitz-Bradley
Office of Utility Consumer Counselor
115 W. Washington Street,
Suite 1500 South
Indianapolis, Indiana 46204
rhelmen@oucc.in.gov
lhitzbradley@oucc.in.gov
infomgt@oucc.in.gov

A courtesy copy has also been provided by email transmission upon the following:

Bette J. Dodd
Lewis & Kappes, P.C.
One American Square, Suite 2500
Indianapolis, Indiana 46282
bdodd@lewis-kappes.com

Dated this 17th day of August, 2020.

Bryan M. Likins

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Determination of Costs for RTO Tracker
Estimates for the Six Months Period of November 2020 through April 2021

Line No.			
1	Total RTO Demand Allocated MISO Net Charges (Sch 2 , Col (a), Line 25)	$	14,491,347
2	Total RTO Energy Allocated MISO Net Charges (Sch 2 , Col (b), Line 25)		2,290,100
3	Annual OSS & BUM Margin to be Returned (Sch 3, Line 14)		-
4	Total RTO Energy Allocated Charges (Credits) (Line 2 + Line 3)	$	2,290,100
5	Prior Period Variance - Under / (Over) Collection (Sch 4, Page 1, Line 8)		(645,735)
6	Total RTO Net Charges (Line 1 + Line 4 + Line 5)	$	16,135,712

Line No.	Rate Code (a)	Demand Allocation Per Cause No.45159* (b)	Demand Allocation % of Total (c)	Total Demand Allocated MISO Costs Col. c x Total Col. d (d)	Energy Allocation Per Cause No. 45159* (e)	Energy Allocation % of Total (f)	Total Energy Allocated MISO Costs Col. f x Total Col. g (g)	Total Energy Allocated OSS Margin Sch 3, Col (t) (h)	RTO Period Variance Sch 4, Pg 1, Col (k) (i)
7	811	$ 508,397,289	35.05%	$ 5,079,051	3,574,056	25.28%	$ 579,017	$ -	$ (596,119)
8	820	914,117	0.06%	9,132	10,918	0.08%	1,769	-	(1,589)
9	821	253,812,406	17.50%	2,535,667	1,692,423	11.97%	274,182	-	(157,275)
10	822	1,211,193	0.08%	12,100	12,282	0.09%	1,990	-	(2,680)
11	823	165,705,139	11.42%	1,655,447	1,324,381	9.37%	214,557	-	175,787
12	824	203,611,356	14.04%	2,034,143	1,887,356	13.35%	305,762	-	146,159
13	825	7,273,007	0.50%	72,660	97,218	0.69%	15,750	-	(6,029)
14	826	125,256,076	8.64%	1,251,348	1,365,256	9.66%	221,179	-	(350,713)
15	831 - Tier 1	120,638,720	8.32%	1,205,219	1,563,558	11.06%	253,305	-	82,033
16	831 - Tier 2	0	0.00%	0	1,904,168	13.47%	308,486	-	90,658
17	832	12,790,750	0.88%	127,784	152,471	1.08%	24,701	-	1,054
18	833	28,801,612	1.99%	287,737	408,867	2.89%	66,239	-	(33,868)
19	841	3,500,918	0.24%	34,975	29,678	0.21%	4,808	-	(13,098)
20	842	111,123	0.01%	1,110	355	0.00%	57	-	(141)
21	844	2,146,284	0.15%	21,442	21,905	0.15%	3,549	-	(1,018)
22	850	7,896,064	0.54%	78,884	42,843	0.30%	6,941	-	13,354
23	855	910,582	0.06%	9,097	6,532	0.05%	1,058	-	(1,299)
24	860	2,615,562	0.18%	26,130	15,291	0.11%	2,477	-	(4,022)
25	Interdpt	4,946,681	0.34%	49,419	26,376	0.19%	4,273	-	13,072
26	Total	$ 1,450,538,879	100.00%	$ 14,491,347	14,135,934	100.00%	$ 2,290,100	$ -	$ (645,735)

*As adjusted per Attachment B.

Line No.	Rate Code (j)	Forecasted Semi-Annual kWh Sales (k)	Demand MISO Component of RTO Rate ($/kWh) Col. (d) / (k) (l)	Energy MISO Component of RTO Rate ($/kWh) Col. (g) / (k) (m)	OSS Margin Component of RTO Rate ($/kWh) Col. (h) / (k) (n)	Variance of RTO Rate ($/kWh) Col. (i) / (k) (o)	Total RTO Rate ($/kWh) Col. (l)+(m)+(n)+(o) (p)
27	811	1,516,562,155	$ 0.003349	$ 0.000382	$ -	$ (0.000393)	$ 0.003338
28	820	9,852,150	0.000927	0.000180	-	(0.000161)	0.000946
29	821	733,910,830	0.003455	0.000374	-	(0.000214)	0.003615
30	822	9,016,106	0.001342	0.000221	-	(0.000297)	0.001266
31	823	542,555,484	0.003051	0.000395	-	0.000324	0.003770
32	824	832,431,268	0.002444	0.000367	-	0.000176	0.002987
33	825	43,010,453	0.001689	0.000366	-	(0.000140)	0.001915
34	826	562,163,992	0.002226	0.000393	-	(0.000624)	0.001995
35	831 - Tier 1	744,956,361	0.001618	0.000340	-	0.000110	0.002068
36	831 - Tier 2	947,911,929	-	0.000325	-	0.000096	0.000421
37	832	82,794,469	0.001543	0.000298	-	0.000013	0.001854
38	833	200,102,343	0.001438	0.000331	-	(0.000169)	0.001600
39	841	17,994,073	0.001944	0.000267	-	(0.000728)	0.001483
40	842	170,178	0.006524	0.000338	-	(0.000828)	0.006034
41	844	10,976,638	0.001953	0.000323	-	(0.000093)	0.002183
42	850	28,582,167	0.002760	0.000243	-	0.000467	0.003470
43	855	2,858,725	0.003182	0.000370	-	(0.000454)	0.003098
44	860	7,834,262	0.003335	0.000316	-	(0.000513)	0.003138
45	Interdpt	12,223,076	0.004043	0.000350	-	0.001069	0.005462
46	Total	6,305,906,659					

Cause No. 44156-RTO-18
Attachment A
SCHEDULE 2

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Determination of Non Fuel Component and MISO Revenue Amounts
Estimates for Six Month Period of November 2020 through April 2021

Line No.	Description	Demand Allocated (a)	Energy Allocated (b)	Total (c) (a) + (b)
	Estimated Schedule 1 - Scheduling, System Control, and Dispatch Service for the Period			
1	Total Estimated Schedule 1	$ -	$ (48,000)	$ (48,000)
	Estimated Schedule 2 - Reactive Supply and Voltage Control for the Period			
	From Generation or Other Source Service			
2	Total Estimated Schedule 2	-	(219,600)	(219,600)
3	Estimated Schedule 7 - Long Tern /Short-Term Firm Point-to-Point Transmission	-	(717,000)	
4	Estimated Schedule 8 - Non-Firm Point-to-Point Transmission Service for the Period	-	(29,400)	
5	Total Estimated Schedule 7 and Schedule 8	-	(746,400)	(746,400)
	Estimated Schedule 10 - FERC-FERC Assessment Fees for the Period			
6	Total Estimated Schedule 10 - FERC	-	494,500	494,500
	Estimated Schedule 10 - ISO Cost Recovery Adder Charges for the Period			
7	Total Estimated Schedule 10	-	1,462,100	1,462,100
	Estimated Schedule 11 - Miscellaneous Transmission Adjustments			
8	Total Estimated Schedule 11	-	-	-
	Estimated Schedule 16 - Financial Transmission Rights Administrative			
	Service Cost Recovery Adder Charges for the Period			
9	Total Estimated Schedule 16	-	20,400	20,400
	Estimated Schedule 17 - Energy Market Support Administrative			
	Service Cost Recovery Adder Charges for the Period			
10	Total Estimated Schedule 17	-	1,203,000	1,203,000
	Estimated Schedule 24 - Control Area Operator Cost Recovery			
	Cost Recovery Adder Charges for the Period			
11	Total Estimated Schedule 24	-	(398,200)	(398,200)
12	Estimated Schedule 26 - Network Upgrade Charge from Transmission	2,481,900	-	
13	Estimated Schedule 26A - Expansion Plan (MVP) Cost Recovery Adder	12,932,500	-	
14	Estimated Schedule 26 - Expansion Plan Cost Recovery Adder Charges for the Period	(852,200)	-	
15	Total Estimated Schedule 26 (Line 12 + Line 13 + Line 14)	14,562,200	-	14,562,200
	Estimated Other Miscellaneous Transmission Schedules/Amounts			
16	Total Estimated Other Miscellaneous Transmission Schedules/Amounts	-	-	-
	Estimated Schedule 37 - Expansion Plan Cost Recovery (FE) Adder Charges for the Period			
17	Total Estimated Schedule 37	(10,200)	-	(10,200)
	Estimated Schedule 38 - Expansion Plan Cost Recovery (DUK) Adder Charges for the Period			
18	Total Estimated Schedule 38	(12,600)	-	(12,600)
	Estimated Schedule 49 - Available System Capacity Cost Recovery (SPP)			
19	Total Estimated Schedule 49	-	33,600	33,600
	Estimated Other MISO Standard Market Design and/or Other			
20	Government Mandated costs for the Period	-	-	-
21	Estimated Real Time Miscellaneous Amount	-	-	-
22	Estimated Real Time Revenue Neutrality Uplift	-	488,700	488,700
23	Estimated Real Time MVP Distribution	(48,053)	-	(48,053)
24	Total Estimated Other MISO Costs (Line 20 + Line 21 + Line 22 + Line 23)	(48,053)	488,700	440,647
25	Total Estimated MISO Charges to be offset with amounts included in Base Rates	$ 14,491,347	$ 2,290,100	$ 16,781,447

Cause No. 44156-RTO-18
Attachment A
SCHEDULE 3

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Determination of Off System Sales Net Revenue included in RTO Tracker
January through December 2020

Line No.	Month (a)	Off System Sales Revenues (b)	Off System Sales Costs (c)	Off System Sales Margins (d) (b) - (c)	Back Up and Maint.* Revenues (e)	Back Up and Maint.* Costs (f)	Back Up and Maint.* Margins (g) (e) - (f)	Total OSS & BUM Margins (h) (d) + (g)
1	January	$ 852,260	$ 617,574	$ 234,686	$ -	$ -	$ -	$ 234,686
2	February	208,621	186,505	22,116	-	-	-	22,116
3	March	48,897	42,247	6,649	-	-	-	6,649
4	April	3,535	2,753	782	-	-	-	782
5	May	-	1	(1)	-	-	-	(1)
6	June	34,170	29,042	5,128	-	-	-	5,128
7	July			-			-	-
8	August			-			-	-
9	September			-			-	-
10	October			-			-	-
11	November			-			-	-
12	December			-			-	-
13	Total	$ 1,147,482	$ 878,122	$ 269,360	$ -	$ -	$ -	$ 269,360

14 Total margins to be returned in current RTO filing $ -

*Refers to Back-Up, Maintenance, and Temporary Services under Rider 876.

		January - April OSS & BUM Margins			May - October OSS & BUM Margins		
	Rate Code (i)	Energy Allocation Per Cause No. 45159* (j)	Energy Allocation % of Total (k)	Energy Allocated OSS & BUM Margins Col (k) x Total Col (l) (l)	Energy Allocation Per Cause No. 45159** (m)	Energy Allocation % of Total (n)	Energy Allocated OSS & BUM Margins Col (n) x Total Col (o) (o)
15	811	$ 3,574,056	28.86%	$ -	$ 3,574,056	25.44%	$ -
16	820	10,918	0.09%	-	10,918	0.08%	-
17	821	1,692,423	13.67%	-	1,692,423	12.05%	-
18	822	12,282	0.10%	-	12,282	0.09%	-
19	823	1,324,381	10.69%	-	1,324,381	9.43%	-
20	824	1,925,038	15.54%	-	1,925,038	13.70%	-
21	825	97,218	0.78%	-	97,218	0.69%	-
22	826	1,327,574	10.72%	-	1,327,574	9.45%	-
23	831 - Tier 1	1,716,774	13.86%	-	1,563,558	11.13%	-
24	831 - Tier 2	-	0.00%	-	1,814,930	12.92%	-
25	832	152,471	1.23%	-	152,471	1.09%	-
26	833	408,867	3.30%	-	408,867	2.91%	-
27	841	29,678	0.24%	-	29,678	0.21%	-
28	842	355	0.00%	-	355	0.00%	-
29	844	21,905	0.18%	-	21,905	0.16%	-
30	850	42,843	0.35%	-	42,843	0.31%	-
31	855	6,532	0.05%	-	6,532	0.05%	-
32	860	15,291	0.12%	-	15,291	0.11%	-
33	Interdpt	26,376	0.21%	-	26,376	0.19%	-
34	Total	$ 12,384,981	100.00%	$ -	$ 14,046,695	100.00%	$ -

		November - December OSS & BUM Margins			
	Rate Code (p)	Energy Allocation Per Cause No. 45159*** (q)	Energy Allocation % of Total (r)	Energy Allocated OSS & BUM Margins Col (r) x Total Col (s) (s)	Energy Allocated Total OSS & BUM Margins Col (l) + Col (o) + Col (s) (t)
35	811	$ 3,574,056	25.28%	$ -	$ -
36	820	10,918	0.08%	-	-
37	821	1,692,423	11.97%	-	-
38	822	12,282	0.09%	-	-
39	823	1,324,381	9.37%	-	-
40	824	1,887,356	13.35%	-	-
41	825	97,218	0.69%	-	-
42	826	1,365,256	9.66%	-	-
43	831 - Tier 1	1,563,558	11.06%	-	-
44	831 - Tier 2	1,904,168	13.47%	-	-
45	832	152,471	1.08%	-	-
46	833	408,867	2.89%	-	-
47	841	29,678	0.21%	-	-
48	842	355	0.00%	-	-
49	844	21,905	0.15%	-	-
50	850	42,843	0.30%	-	-
51	855	6,532	0.05%	-	-
52	860	15,291	0.11%	-	-
53	Interdpt	26,376	0.19%	-	-
54	Total	$ 14,135,934	100.00%	$ -	$ -

* Energy allocators from NIPSCO's Cost of Service study for Cause No. 45159 and for RTO-16 Compliance Filing, adjusted for migrations.
** Energy allocators from NIPSCO's Cost of Service study for Cause No. 45159 and for RTO-17, adjusted for migrations.
*** Energy allocators from NIPSCO's Cost of Service study for Cause No. 45159 and for RTO-18, adjusted for migrations.

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Reconciliation of Costs for RTO Tracker
January through June 2020

Line No.			Demand		Energy		Variance		Total
1	MISO Costs - Demand and Energy Allocated (Sch 5, Pgs 1 & 2)	$	12,493,733	$	2,603,235	$	-	$	15,096,968
2	Annual OSS Margin to be Returned (Sch 4, Pg 3, Col i, Ln 40)		-		1,580,465		-		1,580,465
3	Prior Period Variance to Collect (Return) (Sch 6, Col d, Ln 20)		-		-		(3,899,321)		(3,899,321)
4	Total RTO Costs (Credits)	$	12,493,733	$	4,183,700	$	(3,899,321)	$	12,778,112
5	Energy & Demand Revenues Collected (Sch 4, Pgs 2 & 3)	$	13,018,736	$	3,845,508	$	-	$	16,864,244
6	Prior Period Variance Revenues Returned		-		-		(3,440,397)		(3,440,397)
7	Total Revenues collected	$	13,018,736	$	3,845,508	$	(3,440,397)	$	13,423,847
8	Variance (Line 4 - Line 7)	$	(525,003)	$	338,192	$	(458,924)	$	(645,735)

	Rate Code (a)	Demand Allocated MISO Costs (Sch4, pg2, col i) (b)	Energy Allocated MISO & OSS Costs (Sch4, pg3, col j) (c)	Prior Period Variance (Sch6, col d) (d)	Total RTO Costs Col (b) + (c) + (d) (e)
9	811	$ 4,378,911	$ 1,037,122	$ (1,132,479)	$ 4,283,554
10	820	7,873	3,352	(1,855)	9,370
11	821	2,186,129	477,797	(551,761)	2,112,165
12	822	10,432	3,876	(522)	13,786
13	823	1,427,246	404,356	(303,056)	1,528,546
14	824	1,790,105	568,202	(351,471)	2,006,836
15	825	62,644	28,346	(19,257)	71,733
16	826	1,042,484	373,120	(317,567)	1,098,037
17	831 - Tier 1	1,039,082	936,980	(1,067,200)	908,862
18	831 - Tier 2	-	129,625	-	129,625
19	832	110,168	50,759	(35,297)	125,630
20	833	248,073	125,125	(67,648)	305,550
21	841	30,154	8,691	(12,184)	26,661
22	842	957	102	(321)	738
23	844	18,487	6,309	(5,494)	19,302
24	850	68,011	14,042	(16,089)	65,964
25	855	7,843	2,019	(2,432)	7,430
26	860	22,528	4,365	(6,216)	20,677
27	Interdpt	42,606	9,512	(8,472)	43,646
28	Total	$ 12,493,733	$ 4,183,700	$ (3,899,321)	$ 12,778,112

	Rate Code (f)	Demand Revenues Collected (g)	Energy Revenues Collected (h)	Prior Period Variance Revenues Credited (i)	Total Revenue Collected Col (g) + (h) + (i) (j)	RTO Period Variance Col (e) - (j) (k)
29	811	$ 4,867,793	$ 1,090,858	$ (1,078,978)	$ 4,879,673	$ (596,119)
30	820	8,832	3,935	(1,807)	10,959	(1,589)
31	821	2,289,031	473,691	(493,283)	2,269,440	(157,275)
32	822	11,217	4,753	497	16,466	(2,680)
33	823	1,238,099	334,146	(219,486)	1,352,759	175,787
34	824	1,667,779	490,620	(297,722)	1,860,677	146,159
35	825	66,814	28,760	(17,811)	77,762	(6,029)
36	826	1,346,299	458,932	(356,481)	1,448,750	(350,713)
37	831 - Tier 1	960,651	703,627	(837,448)	826,829	82,033
38	831 - Tier 2	-	38,967	-	38,967	90,658
39	832	108,666	46,140	(30,231)	124,576	1,054
40	833	272,896	130,765	(64,243)	339,418	(33,868)
41	841	43,075	11,803	(15,119)	39,759	(13,098)
42	842	1,080	91	(292)	879	(141)
43	844	19,019	6,174	(4,872)	20,320	(1,018)
44	850	53,494	10,096	(10,979)	52,610	13,354
45	855	8,956	2,182	(2,409)	8,729	(1,299)
46	860	26,041	4,885	(6,226)	24,699	(4,022)
47	Interdpt	28,994	5,084	(3,504)	30,574	13,072
48	Total	$ 13,018,736	$ 3,845,508	$ (3,440,397)	$ 13,423,847	$ (645,735)

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Reconciliation of Costs for RTO Tracker
January through June 2020

Line No.	Rate Code (a)	Demand Allocated Charges January - April 2020: Demand Allocation Per Cause No. 45159 * (b)	Demand Allocation % of Total Col (b)/Total Col (b) (c)	Total Demand Allocated MISO Costs from Sch 5, pg 1, Col (e) Col. c x Total Col. d (d)	Demand Allocated Charges May - June 2020: Demand Allocation Per Cause No. 45159 ** (e)	Demand Allocation % of Total Col (e)/Total Col (e) (f)	Total Demand Allocated MISO Costs from Sch 5, pg 1, Col (h) Col. (f) x Total Col. (g) (g)
1	811	$ 508,397,289	35.05%	$ 3,015,563	$ 508,397,289	35.05%	$ 1,363,348
2	820	914,117	0.06%	5,422	914,117	0.06%	2,451
3	821	253,812,406	17.50%	1,505,491	253,812,406	17.50%	680,638
4	822	1,211,193	0.08%	7,184	1,211,193	0.08%	3,248
5	823	165,705,139	11.42%	982,882	165,705,139	11.42%	444,364
6	824	207,833,587	14.33%	1,232,767	207,833,587	14.33%	557,338
7	825	7,273,007	0.50%	43,140	7,273,007	0.50%	19,504
8	826	121,033,845	8.34%	717,913	121,033,845	8.34%	324,571
9	831 - Tier 1	120,638,720	8.32%	715,570	120,638,720	8.32%	323,512
10	831 - Tier 2	-	0.00%	-	-	0.00%	-
11	832	12,790,750	0.88%	75,868	12,790,750	0.88%	34,300
12	833	28,801,612	1.99%	170,837	28,801,612	1.99%	77,236
13	841	3,500,918	0.24%	20,766	3,500,918	0.24%	9,388
14	842	111,123	0.01%	659	111,123	0.01%	298
15	844	2,146,284	0.15%	12,731	2,146,284	0.15%	5,756
16	850	7,896,064	0.54%	46,836	7,896,064	0.54%	21,175
17	855	910,582	0.06%	5,401	910,582	0.06%	2,442
18	860	2,615,562	0.18%	15,514	2,615,562	0.18%	7,014
19	Interdpt	4,946,681	0.34%	29,341	4,946,681	0.34%	13,265
20	Total	$ 1,450,538,879	100.00%	$ 8,603,885	$ 1,450,538,879	100.00%	$ 3,889,848

* Demand allocators from NIPSCO's Cost of Service study for Cause No. 45159 and for RTO-16 Compliance Filing, adjusted for migrations
** Demand allocators from NIPSCO's Cost of Service study for Cause No. 45159 and for RTO-17, adjusted for migrations.

Line No.	Rate Code (h)	Total Demand Allocated MISO Costs to Recover Col(d) + Col(g) (i)	Demand Revenues Collected (j)	Demand Revenue Variance Col. (i) - Col (j) (k)
21	811	$ 4,378,911	$ 4,867,793	$ (488,882)
22	820	7,873	8,832	(959)
23	821	2,186,129	2,289,031	(102,902)
24	822	10,432	11,217	(785)
25	823	1,427,246	1,238,099	189,147
26	824	1,790,105	1,667,779	122,326
27	825	62,644	66,814	(4,170)
28	826	1,042,484	1,346,299	(303,815)
29	831 - Tier 1	1,039,082	960,651	78,431
30	831 - Tier 2	-	-	-
31	832	110,168	108,666	1,502
32	833	248,073	272,896	(24,823)
33	841	30,154	43,075	(12,921)
34	842	957	1,080	(123)
35	844	18,487	19,019	(532)
36	850	68,011	53,494	14,517
37	855	7,843	8,956	(1,113)
38	860	22,528	26,041	(3,513)
39	Interdpt	42,606	28,994	13,612
40	Total	$ 12,493,733	$ 13,018,736	$ (525,003)

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Reconciliation of Costs for RTO Tracker
January through June 2020

		Energy Allocated Charges January - April 2020			Energy Allocated Charges May - June 2020		
Line No.	Rate Code (a)	Energy Allocation Per Cause No. 45159 * (b)	Energy Allocation % of Total Col (b)/Total Col (b) (c)	Total Energy Allocated MISO Costs from Sch 5, pg 2, col e Col (c) x Total Col (d) (d)	Energy Allocation Per Cause No. 45159 ** (e)	Energy Allocation % of Total Col (e)/Total Col (e) (f)	Total Energy Allocated MISO Costs from Sch 5, pg 2, col h Col (f) x Total Col (g) (g)
1	811	$ 3,574,056	28.86%	$ 461,728	$ 3,574,056	25.44%	$ 255,264
2	820	10,918	0.09%	1,410	10,918	0.08%	780
3	821	1,692,423	13.67%	218,642	1,692,423	12.05%	120,875
4	822	12,282	0.10%	1,587	12,282	0.09%	877
5	823	1,324,381	10.69%	171,095	1,324,381	9.43%	94,589
6	824	1,925,038	15.54%	248,693	1,925,038	13.70%	137,489
7	825	97,218	0.78%	12,559	97,218	0.69%	6,943
8	826	1,327,574	10.72%	171,508	1,327,574	9.45%	94,817
9	831 - Tier 1	1,716,774	13.86%	221,788	1,563,558	11.13%	111,672
10	831 - Tier 2	-	0.00%	-	1,814,930	12.92%	129,625
11	832	152,471	1.23%	19,697	152,471	1.09%	10,890
12	833	408,867	3.30%	52,821	408,867	2.91%	29,202
13	841	29,678	0.24%	3,834	29,678	0.21%	2,120
14	842	355	0.00%	46	355	0.00%	25
15	844	21,905	0.18%	2,830	21,905	0.16%	1,565
16	850	42,843	0.35%	5,535	42,843	0.31%	3,060
17	855	6,532	0.05%	844	6,532	0.05%	467
18	860	15,291	0.12%	1,975	15,291	0.11%	1,092
19	Interdpt	26,376	0.21%	3,407	26,376	0.19%	1,884
20	Total	$ 12,384,981	100.00%	$ 1,599,999	$ 14,046,695	100.00%	$ 1,003,236

* Energy allocators from NIPSCO's Cost of Service study for Cause No. 45159 and for RTO-16 Compliance Filing, adjusted for migrations
** Energy allocators from NIPSCO's Cost of Service study for Cause No. 45159 and for RTO-17, adjusted for migrations.

	Rate Code (h)	Total Energy Allocated OSS Rev Sch. 6 Col (f) (i)	Total Energy Allocation to Recover Col(d) + Col(g) + Col(i) (j)	Energy Revenues Collected (k)	Revenues Variance Col. (j) - Col (k) (l)
21	811	$ 320,130	$ 1,037,122	$ 1,090,858	$ (53,736)
22	820	1,162	3,352	3,935	(583)
23	821	138,280	477,797	473,691	4,106
24	822	1,412	3,876	4,753	(877)
25	823	138,672	404,356	334,146	70,210
26	824	182,020	568,202	490,620	77,582
27	825	8,844	28,346	28,760	(414)
28	826	106,795	373,120	458,932	(85,812)
29	831 - Tier 1	603,520	936,980	703,627	233,353
30	831 - Tier 2	-	129,625	38,967	90,658
31	832	20,172	50,759	46,140	4,619
32	833	43,102	125,125	130,765	(5,640)
33	841	2,737	8,691	11,803	(3,112)
34	842	31	102	91	11
35	844	1,914	6,309	6,174	135
36	850	5,447	14,042	10,096	3,946
37	855	708	2,019	2,182	(163)
38	860	1,298	4,365	4,885	(520)
39	Interdpt	4,221	9,512	5,084	4,428
40	Total	$ 1,580,465	$ 4,183,700	$ 3,845,508	$ 338,192

Cause No. 44156-RTO-18
Attachment A
SCHEDULE 5
Page 1 of 2

NORTHERN INDIANA PUBLIC SERVICE COMPANY
MISO Cost and Revenue Adjustment
Reconciliation of MISO costs included in RTO Tracker
January through June 2020

Line No.		Jan-20 (a)	Feb-20 (b)	Mar-20 (c)	Apr-20 (d)	Subtotal (e)	May-20 (f)	Jun-20 (g)	Subtotal (h)	Total (i)
	Demand Allocated Costs									
1	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan									
2	Current Portion	$ 259,689	$ 245,261	$ 268,881	$ 206,453	**$ 980,284**	$ 266,311	$ 321,089	**$ 587,400**	**$ 1,567,684**
3	FERC Order (EL14-12 & EL15-45) Settlement of ROE Refund				(114,209)	**(114,209)**			**-**	**(114,209)**
4	Total	259,689	245,261	268,881	92,244	**866,075**	266,311	321,089	**587,400**	**1,453,475**
5	Schedule 26A - Expansion Plan (MVP) Cost Recovery Adder	2,227,338	2,018,425	2,207,272	1,642,792	**8,095,827**	1,756,293	1,798,442	**3,554,735**	**11,650,562**
6	Schedule 26C - Expansion Plan (TMEP) Cost Recovery Adder	31,123	31,225	31,181	31,070	**124,599**	31,181	31,182	**62,363**	**186,962**
7	Schedule 26 - Expansion Plan Reimbursement for the Period									
8	Current Portion	(128,294)	(137,656)	(123,410)	(125,824)	**(515,184)**	(141,272)	(164,883)	**(306,155)**	**(821,339)**
9	FERC Order (EL14-12 & EL15-45) Settlement of ROE Refund				83,961	**83,961**			**-**	**83,961**
10	Total	(128,294)	(137,656)	(123,410)	(41,863)	**(431,223)**	(141,272)	(164,883)	**(306,155)**	**(737,378)**
11	Auction Revenue Right/Real Time MVP Distribution	(21,492)	(11,818)	(2,730)	(2,894)	**(38,934)**	(1,739)	882	**(857)**	**(39,791)**
12	Schedule 37 - Expansion Plan Cost Recovery Adder									
13	Current Portion	(1,700)	(1,652)	(1,700)	(1,700)	**(6,752)**	(1,700)	(1,705)	**(3,405)**	**(10,157)**
14	FERC Order (EL14-12 & EL15-45) Settlement of ROE Refund				1,014	**1,014**			**-**	**1,014**
15	Total	(1,700)	(1,652)	(1,700)	(686)	**(5,738)**	(1,700)	(1,705)	**(3,405)**	**(9,143)**
16	Schedule 38 - Expansion Plan Cost Recovery Adder									
17	Current Portion	(2,119)	(2,055)	(2,119)	(2,119)	**(8,412)**	(2,119)	(2,114)	**(4,233)**	**(12,645)**
18	FERC Order (EL14-12 & EL15-45) Settlement of ROE Refund				1,691	**1,691**			**-**	**1,691**
19	Total	(2,119)	(2,055)	(2,119)	(428)	**(6,721)**	(2,119)	(2,114)	**(4,233)**	**(10,954)**
20	Schedule 39 - MVP Cost Recovery Adder	-	-	-	-	-	-		-	-
21	Total MISO demand related costs to be recovered	$ 2,364,545	$ 2,141,730	$ 2,377,375	$ 1,720,235	**$ 8,603,885**	$ 1,906,955	$ 1,982,893	**$ 3,889,848**	**$ 12,493,733**

NORTHERN INDIANA PUBLIC SERVICE COMPANY
MISO Cost and Revenue Adjustment
Reconciliation of MISO costs included in RTO Tracker
January through June 2020

Line No.		Jan-20 (a)	Feb-20 (b)	Mar-20 (c)	Apr-20 (d)	Subtotal (e)	May-20 (f)	Jun-20 (g)	Subtotal (h)	Total (i)
	Energy Allocated Costs									
1	Schedule 1 - Scheduling, System Control, and Dispatch Service for the Period	$ (8,963)	$ (8,281)	$ (8,198)	$ (7,965)	**$ (33,407)**	$ (8,158)	$ (7,149)	**$ (15,307)**	**$ (48,714)**
2	Schedule 2 - Reactive Supply and Voltage Control for the Period From Generation or Other Source Service	(40,567)	(37,295)	(36,851)	(35,807)	**(150,520)**	(36,526)	(33,784)	**(70,310)**	**(220,830)**
3	Schedule 7 - Long Tern /Short-Term Firm Point-to-Point Transmission									
4	Current Portion	(121,481)	(110,853)	(121,178)	(117,089)	**(470,601)**	(129,466)	(128,343)	**(257,809)**	**(728,410)**
5	FERC Order (EL14-12 & EL15-45) Settlement of ROE Refund				24,151	**24,151**			**-**	**24,151**
6	Total	(121,481)	(110,853)	(121,178)	(92,938)	**(446,450)**	(129,466)	(128,343)	**(257,809)**	**(704,259)**
7	Schedule 8 - Non-Firm Point-to-Point Transmission Service for the Period									
8	Current Portion	(5,688)	(3,541)	(5,030)	(4,764)	**(19,023)**	(8,226)	(5,591)	**(13,817)**	**(32,840)**
9	FERC Order (EL14-12 & EL15-45) Settlement of ROE Refund				3,179	**3,179**			**-**	**3,179**
10	Total	(5,688)	(3,541)	(5,030)	(1,585)	**(15,844)**	(8,226)	(5,591)	**(13,817)**	**(29,661)**
11	Schedule 10 - FERC-FERC Assessment Fees for the Period	83,021	80,579	85,954	65,998	**315,552**	85,132	102,254	**187,386**	**502,938**
12	Schedule 10 - ISO Cost Recovery Adder Charges for the Period	187,530	294,303	224,691	301,445	**1,007,969**	291,747	221,740	**513,487**	**1,521,456**
13	Schedule 11 - Miscellaneous Transmission Adjustments	-	-	-	-	**-**	-	-	**-**	**-**
14	Schedule 16 - Financial Transmission Rights Administrative Service Cost Recovery Adder Charges for the Period	2,848	2,495	3,504	1,978	**10,825**	1,390	2,667	**4,057**	**14,882**
15	Schedule 17 - Energy Market Support Administrative Service Cost Recovery Adder Charges for the Period	227,456	185,989	138,878	188,707	**741,030**	139,244	202,489	**341,733**	**1,082,763**
16	Schedule 24 - Control Area Operator Cost Recovery Cost Recovery Adder Charges for the Period	(60,656)	(62,668)	(60,139)	(59,317)	**(242,780)**	(67,459)	(74,961)	**(142,420)**	**(385,200)**
17	Schedule 49 - Available System Capacity Usage	38,877	54,137	49,924	4,769	**147,707**	4,791	4,216	**9,007**	**156,714**
18	Other Miscellaneous Transmission Schedules/Amounts									
19	Current Portion	-	-	(93)	200	**107**	305	(39)	**266**	**373**
20	FERC Order (EL14-12 & EL15-45) Settlement of ROE Refund				(36)	**(36)**			**-**	**(36)**
21	Total	-	-	(93)	164	**71**	305	(39)	**266**	**337**
22	Real Time Miscellaneous Amount	-	-	4	(34,690)	**(34,686)**	26	236,615	**236,641**	**201,955**
23	Real Time Revenue Neutrality Uplift	59,868	70,591	47,269	122,804	**300,532**	229,641	(19,319)	**210,322**	**510,854**
24	Total MISO energy allocated costs to be recovered	$ 362,245	$ 465,456	$ 318,735	$ 453,563	**$ 1,599,999**	$ 502,441	$ 500,795	**$ 1,003,236**	**$ 2,603,235**

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Distribution of Variance and OSS Margin

Line No.	Rate	RTO-16 Variance included in RTO-18 Reconciliation	RTO-17 Variance included in RTO-18 Reconciliation	Total Variance included in RTO-18 Reconciliation	Total RTO-17 OSS Margin to be Returned	RTO-17 OSS Margin to be Returned in RTO-18 Reconciliation	RTO-17 OSS Margin to be Returned in RTO-19 Reconciliation
	(a)	(b)	(c)	(d) = (b) + (c)	(e)	(f) = ((e) / 6) * 2	(g) = (e) - (f)
1	811	$ (650,419)	$ (482,060)	$ (1,132,479)	$ 960,389	320,130	$ 640,259
2	820	(1,343)	(512)	(1,855)	3,485	1,162	2,323
3	821	(336,273)	(215,488)	(551,761)	414,839	138,280	276,559
4	822	(1,446)	924	(522)	4,236	1,412	2,824
5	823	(171,342)	(131,714)	(303,056)	416,015	138,672	277,343
6	824	(199,799)	(151,672)	(351,471)	546,059	182,020	364,039
7	825	(12,481)	(6,776)	(19,257)	26,531	8,844	17,687
8	826	(206,967)	(110,600)	(317,567)	320,385	106,795	213,590
9	831 - Tier 1	(673,786)	(393,414)	(1,067,200)	1,810,561	603,520	1,207,041
10	831 - Tier 2	-	-	-	-	-	-
11	832	(24,331)	(10,966)	(35,297)	60,515	20,172	40,343
12	833	(38,250)	(29,398)	(67,648)	129,307	43,102	86,205
13	841	(8,262)	(3,922)	(12,184)	8,211	2,737	5,474
14	842	(205)	(116)	(321)	93	31	62
15	844	(3,372)	(2,122)	(5,494)	5,742	1,914	3,828
16	850	(11,181)	(4,908)	(16,089)	16,340	5,447	10,893
17	855	(1,562)	(870)	(2,432)	2,125	708	1,417
18	860	(3,768)	(2,448)	(6,216)	3,893	1,298	2,595
19	Interdpt	(1,816)	(6,656)	(8,472)	12,664	4,221	8,443
20	Total	$ (2,346,603)	$ (1,552,718)	$ (3,899,321)	$ 4,741,390	$ 1,580,465	$ 3,160,925

	Rate	Total RTO-18 Variance to be Recovered/(Returned) (Sch 4, Pg 1, col. k)	RTO-18 Variance to be Returned in RTO-19	RTO-18 Variance to be Returned in RTO-20
	(h)	(i)	(j) = ((i) / 6) * 2	(k) = (i) - (j)
21	811	$ (596,119)	(198,706)	$ (397,413)
22	820	(1,589)	(530)	(1,059)
23	821	(157,275)	(52,425)	(104,850)
24	822	(2,680)	(893)	(1,787)
25	823	175,787	58,596	117,191
26	824	146,159	48,720	97,439
27	825	(6,029)	(2,010)	(4,019)
28	826	(350,713)	(116,904)	(233,809)
29	831 - Tier 1	82,033	27,344	54,689
30	831 - Tier 2	90,658	30,219	60,439
31	832	1,054	351	703
32	833	(33,868)	(11,289)	(22,579)
33	841	(13,098)	(4,366)	(8,732)
34	842	(141)	(47)	(94)
35	844	(1,018)	(339)	(679)
36	850	13,354	4,451	8,903
37	855	(1,299)	(433)	(866)
38	860	(4,022)	(1,341)	(2,681)
39	Interdpt	13,072	4,357	8,715
40	Total	$ (645,735)	$ (215,245)	$ (430,490)

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Estimates for Six Month Period of November 2020 through April 2021
Demand and Energy Allocators
(Includes Customer Migrations and Other Adjustments)

Cause No. 44156-RTO-18
Attachment B

Demand Allocation					
Rate	**% Allocation on Revenue***	**Demand - Total Revenue**	**Customer Migration or Other Adjustments**	**Adjusted Demand - Total Revenue**	**Adjusted % Allocation on Total Revenue**
Rate 811	35.05%	$ 508,397,289	$ -	$ 508,397,289	35.05%
Rate 820	0.06%	914,117	-	914,117	0.06%
Rate 821	17.50%	253,812,406	-	253,812,406	17.50%
Rate 822	0.08%	1,211,193	-	1,211,193	0.08%
Rate 823	11.42%	165,705,139	-	165,705,139	11.42%
Rate 824	14.33%	207,833,587	(4,222,231)	203,611,356	14.04%
Rate 825	0.50%	7,273,007	-	7,273,007	0.50%
Rate 826	8.34%	121,033,845	4,222,231	125,256,076	8.64%
Rate 831 - Tier 1	8.32%	152,266,583	(31,627,863)	120,638,720	8.32%
Rate 831 - Tier 2	0.00%	-	-	-	0.00%
Rate 832	0.88%	12,790,750	-	12,790,750	0.88%
Rate 833	1.99%	28,801,612	-	28,801,612	1.99%
Rate 841	0.24%	3,500,918	-	3,500,918	0.24%
Rate 842	0.01%	111,123	-	111,123	0.01%
Rate 844	0.15%	2,146,284	-	2,146,284	0.15%
Rate 850	0.54%	7,896,064	-	7,896,064	0.54%
Rate 855	0.06%	910,582	-	910,582	0.06%
Rate 860	0.18%	2,615,562	-	2,615,562	0.18%
Interdepartmental	0.34%	4,946,681	-	4,946,681	0.34%
Total	**100.00%**	**$ 1,482,166,742**	**$ (31,627,863)**	**$ 1,450,538,879**	**100.00%**

*Demand Allocation per Cause No. 45159

Energy Allocation					
Rate Code	**% Allocation on Energy Sales***	**Energy Sales at the Generator (MWh)***	**Customer Migration or Other Adjustments**	**Adjusted Energy Sales at Generator (MWh)**	**Adjusted % Allocation on Total Sales**
Rate 811	28.86%	3,574,056	-	3,574,056	25.28%
Rate 820	0.09%	10,918	-	10,918	0.08%
Rate 821	13.67%	1,692,423	-	1,692,423	11.97%
Rate 822	0.10%	12,282	-	12,282	0.09%
Rate 823	10.69%	1,324,381	-	1,324,381	9.37%
Rate 824	15.54%	1,925,038	(37,682)	1,887,356	13.35%
Rate 825	0.78%	97,218	-	97,218	0.69%
Rate 826	10.72%	1,327,574	37,682	1,365,256	9.66%
Rate 831 - Tier 1	13.86%	1,716,774	(153,216)	1,563,558	11.06%
Rate 831 - Tier 2	0.00%		1,904,168	1,904,168	13.47%
Rate 832	1.23%	152,471	-	152,471	1.08%
Rate 833	3.30%	408,867	-	408,867	2.89%
Rate 841	0.24%	29,678	-	29,678	0.21%
Rate 842	0.00%	355	-	355	0.00%
Rate 844	0.18%	21,905	-	21,905	0.15%
Rate 850	0.35%	42,843	-	42,843	0.30%
Rate 855	0.05%	6,532	-	6,532	0.05%
Rate 860	0.12%	15,291	-	15,291	0.11%
Interdepartmental	0.21%	26,376	-	26,376	0.19%
Total	**100.00%**	**12,384,981**	**1,750,952**	**14,135,934**	**100.00%**

*Energy Allocation per Cause No. 45159

APPENDIX C
REGIONAL TRANSMISSION ORGANIZATION ADJUSTMENT FACTOR

As shown in Appendix A, the Regional Transmission Organization ("RTO") Adjustment Factor in Rates 811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1 and Tier 2, 832, 833, 841, 842, 844, 850, 855 and 860, and Rider 876 shall be computed in accordance with Rider 871 – Adjustment of Charges for Regional Transmission Organization.

Effective for bills rendered during the November 2020 through April 2021 billing cycles, or until new factors are approved by the Commission, the RTO Factor shall be:

RATE SCHEDULES

Rate	Charge
Rate 811	A charge of $0.003338 per kWh used per month
Rate 820	A charge of $0.000946 per kWh used per month
Rate 821	A charge of $0.003615 per kWh used per month
Rate 822	A charge of $0.001266 per kWh used per month
Rate 823	A charge of $0.003770 per kWh used per month
Rate 824	A charge of $0.002987 per kWh used per month
Rate 825	A charge of $0.001915 per kWh used per month
Rate 826	A charge of $0.001995 per kWh used per month
Rate 831 Tier 1	A charge of $0.002068 per kWh used per month
Rate 831 Tier 2	A charge of $0.000421 per kWh used per month
Rate 832	A charge of $0.001854 per kWh used per month
Rate 833	A charge of $0.001600 per kWh used per month
Rate 841	A charge of $0.001483 per kWh used per month
Rate 842	A charge of $0.006034 per kWh used per month
Rate 844	A charge of $0.002183 per kWh used per month
Rate 850	A charge of $0.003470 per kWh used per month
Rate 855	A charge of $0.003098 per kWh used per month
Rate 860	A charge of $0.003138 per kWh used per month
Rider 876	See note below

The RTO Factor for Rider 876 will be the RTO Factor associated with the firm service under Rate Schedule 831 Tier 1 and 831 Tier 2 being used in conjunction with this Rider.

NORTHERN INDIANA PUBLIC SERVICE COMPANY
IURC Electric Service Tariff
Original Volume No. 14
Cancelling All Previously Approved Tariffs

Second ~~First~~ Revised Sheet No. 204
Superseding
First Revised ~~Original~~ Sheet No. 204

APPENDIX C
REGIONAL TRANSMISSION ORGANIZATION ADJUSTMENT FACTOR

Sheet No. 1 of 1

As shown in Appendix A, the Regional Transmission Organization ("RTO") Adjustment Factor in Rates 811, 820, 821, 822, 823, 824, 825, 826, 831 Tier 1 and Tier 2, 832, 833, 841, 842, 844, 850, 855 and 860, and Rider 876 shall be computed in accordance with Rider 871 – Adjustment of Charges for Regional Transmission Organization.

Effective for bills rendered during the November 2020 through April 2021 ~~May through October 2020~~ billing cycles, or until new factors are approved by the Commission, the RTO Factor shall be:

RATE SCHEDULES

Rate	Charge
Rate 811	A charge of $0.003338~~2619~~ per kWh used per month
Rate 820	A charge of $0.000946~~12230~~ per kWh used per month
Rate 821	A charge of $0.003615~~2848~~ per kWh used per month
Rate 822	A charge of $0.001266~~24584~~ per kWh used per month
Rate 823	A charge of $0.003770~~2786~~ per kWh used per month
Rate 824	A charge of $0.002987~~2504~~ per kWh used per month
Rate 825	A charge of $0.001915~~1959~~ per kWh used per month
Rate 826	A charge of $0.001995~~1997~~ per kWh used per month
Rate 831 Tier 1	A charge of $0.002068~~2628~~ per kWh used per month
Rate 831 Tier 2	A charge of $0.000421~~708~~ per kWh used per month
Rate 832	A charge of $0.001854~~1937~~ per kWh used per month
Rate 833	A charge of $0.001600~~1755~~ per kWh used per month
Rate 841	A charge of $0.001483~~2085~~ per kWh used per month
Rate 842	A charge of $0.006034~~4464~~ per kWh used per month
Rate 844	A charge of $0.002183~~2265~~ per kWh used per month
Rate 850	A charge of $0.003470~~3259~~ per kWh used per month
Rate 855	A charge of $0.003098~~2357~~ per kWh used per month
Rate 860	A charge of $0.003138~~3742~~ per kWh used per month
Rider 876	See note below

The RTO Factor for Rider 876 will be the RTO Factor associated with the firm service under Rate Schedule 831 Tier 1 and 831 Tier 2 being used in conjunction with this Rider.

Issued Date
10/ ~~04/29~~/2020

Effective Date
10/29~~04/30~~/2020

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2020

Northern Indiana Public Service Company LLC

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31, column 5)					$ 128,992,628
	REVENUE CREDITS	(Note T)				
2	Account No. 454	(page 4, line 34, column 5)	0	TP	1.00000	0
3	Account No. 456.1	(page 4, line 37, column 5)	2,187,600	TP	1.00000	2,187,600
4	Revenues from Grandfathered Interzonal Transactions		0	TP	1.00000	0
5	Revenues from service provided by the ISO at a discount		0	TP	1.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)					2,187,600
6a	Historic Year Actual ATRR					100,195,448
6b	Projected ATRR from Prior Year	Input from Prior Year				110,495,513
6c	Prior Year ATRR True-Up	(line 6a - line 6b)				(10,300,065)
6d	Prior Year Divisor True-Up	(Note BB)				(3,717,054)
6e	Interest on Prior Year True-Up					(1,356,267)
7	NET REVENUE REQUIREMENT	(line 1 - line 6 + line 6c through 6e)				$ 111,431,642
	DIVISOR					
8	Average of 12 coincident system peaks for requirements (RQ) service			(Note A)		2,390,813
9	Plus 12 CP of firm bundled sales over one year not in line 8			(Note B)		0
10	Plus 12 CP of Network Load not in line 8			(Note C)		296,062
11	Less 12 CP of firm P-T-P over one year (enter negative)			(Note D)		0
12	Plus Contract Demand of firm P-T-P over one year					0
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0
15	Divisor (sum lines 8-14)					2,686,875

Line No.			Peak Rate		Off-Peak Rate
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	41.473		
17	Network & P-to-P Rate ($/kW/Mo)	(line 16 / 12)	3.456		
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.798		$0.798
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	0.160	Capped at weekly rate	$0.114
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160 times 1000; □ line 16 / 8,760 times 1,000)	9.969	Capped at weekly and daily rates	$4.734
21	FERC Annual Charge ($/MWh)	(Note E)	$0.0000 Short Term		$0.0000 Short Term
22			$0.0000 Long Term		$0.0000 Long Term

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2020

Northern Indiana Public Service Company LLC

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE (Note Z, Note GG)					
1	Production	205.46.g	4,091,215,408	NA		
2	Transmission	207.58.g	1,840,513,632	TP	1.00000	1,840,513,632
3	Distribution	207.75.g	2,303,597,766	NA		
4	General & Intangible	205.5.g & 207.99.g	163,677,191	W/S	0.14440	23,634,564
5	Common	356.1 (Note O)	270,464,826	CE	0.14440	39,054,423
6	TOTAL GROSS PLANT (sum lines 1-5)		8,669,468,823	GP=	21.953%	1,903,202,619
	ACCUMULATED DEPRECIATION (Note Z, Note GG)					
7	Production	219.20-24.c	2,132,195,849	NA		
8	Transmission	219.25.c	590,132,641	TP	1.00000	590,132,641
9	Distribution	219.26.c	1,044,210,542	NA		
10	General & Intangible	219.28.c & 200.21.c	119,026,226	W/S	0.14440	17,187,080
11	Common	356.1 (Note O)	204,857,952	CE	0.14440	29,580,960
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		4,090,423,210			636,900,680
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	1,959,019,559			
14	Transmission	(line 2- line 8)	1,250,380,991			1,250,380,991
15	Distribution	(line 3 - line 9)	1,259,387,224			
16	General & Intangible	(line 4 - line 10)	44,650,965			6,447,484
17	Common	(line 5 - line 11)	65,606,874			9,473,463
18	TOTAL NET PLANT (sum lines 13-17)		4,579,045,613	NP=	27.654%	1,266,301,938
	100% CWIP Recovery for Commission Approved Order					
18a	No. 679 Transmission Projects (Note Z)	216.b	0	NA	1.00000	0
	ADJUSTMENTS TO RATE BASE					
19	Account No. 281 (enter negative) (Note F, Note AA)	273.8.k	0	NA	zero	0
20	Account No. 282 (enter negative) (Note F, Note AA)	275.2.k	-1,181,531,699	NP	0.27654	-326,744,044
21	Account No. 283 (enter negative) (Note F, Note AA)	277.9.k	-91,763,681	NP	0.27654	-25,376,582
22	Account No. 190 (Note F, Note AA)	234.8.c	230,825,481	NP	0.27654	63,833,117
23	Account No. 255 (enter negative) (Note F, Note AA)	267.8.h	-20,617	NP	0.27654	-5,701
23a	Unamortized Balance of Abandoned Plant	(Note Y, Note Z)	0	NA	1.00000	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23a)		-1,042,490,516			-288,293,211
25	LAND HELD FOR FUTURE USE (Note AA)	214.x.d (Note G)	3,380,616	TP	1.00000	3,380,616
	WORKING CAPITAL (Note H)					
26	CWC	1/8 page 3, line 8, column 3 & 5	27,447,165			5,859,656
27	Materials & Supplies (Note G, Note FF)	227.8.c & .16.c	37,649,722	TE	0.93025	35,023,748
28	Prepayments (Account 165, Note AA)	111.57.c	30,210,907	GP	0.21953	6,632,180
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		95,307,794			47,515,584
30	RATE BASE (sum lines 18, 18a, 24, 25, & 29)		3,635,243,507			1,028,904,928

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2020

Northern Indiana Public Service Company LLC

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M (Note EE)					
1	Transmission	321.112.b	56,429,251	TE	0.93025	52,493,452
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)		34,098,034		1.00000	34,098,034
2	Less Account 565	321.96.b	0	TE	0.93025	0
3	A&G	323.197.b	199,873,328	W/S	0.14440	28,861,193
4	Less FERC Annual Fees		1,211,800	W/S	0.14440	174,981
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		1,415,427	W/S	0.14440	204,384
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.93025	0
6	Common	356.1 (Note O)	0	CE	0.14440	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 1a, 2, 4, 5)		219,577,318			46,877,246
	DEPRECIATION AND AMORTIZATION EXPENSE (Note GG)					
9	Transmission	336.7.b	48,284,427	TP	1.00000	48,284,427
9a	Abandoned Plant Amortization	(Note Y)	0	NA	1.00000	0
10	General & Intangible	336.10.f & 336.1.f	2,440,460	W/S	0.14440	352,396
11	Common	336.11.f (Note O)	16,220,945	CE	0.14440	2,342,263
12	TOTAL DEPRECIATION	(sum lines 9 - 11)	66,945,832			50,979,086
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i	10,117,295	W/S	0.14440	1,460,911
14	Highway and vehicle	263.i	0	W/S	0.14440	0
15	PLANT RELATED					
16	Property	263.i	23,499,231	GP	0.21953	5,158,770
17	Gross Receipts	263.i	24,299,885	NA	zero	0
18	Other	263.i	0	GP	0.21953	0
19	Payments in lieu of taxes		0	GP	0.21953	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		57,916,411			6,619,682
	INCOME TAXES	(Note K)				
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		25.25%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		24.80%			
	where WCLTD=(page 4, line 27) and R= (page 4, line 30) and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from line 21)		1.3377			
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0			
24a	(Excess)/Deficient Deferred Income Taxes (Note II)		-9,199,823			
24b	Tax Effect of Permanent Differences and AFUDC Equity (Note JJ)		902,766			
25	Income Tax Calculation = line 22 * line 28		73,640,141	NA		20,842,814
26	ITC adjustment (line 23 * line 24)		0	NP	0.27654	0
26a	(Excess)/Deficient Deferred Income Tax Adjustment (Line 23 * Line 24a)		-12,306,838	NP	0.27654	-3,403,367
26b	Permanent Differences and AFUDC Equity Tax Adjustment (Line 23 * Line 24b)		1,207,653	NP	0.27654	333,968
27	Total Income Taxes	(line 25 plus line 26 plus Lines 26a and 26b	62,540,956			17,773,415
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		296,935,574	NA		84,043,469
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		703,916,091			206,292,897
30	LESS ATTACHMENT GG ADJUSTMENT [Attachment GG, page 2, line 3, column 10] (Note W) [Revenue Requirement for facilities included on page 2, line 2, and also included in Attachment GG]		3,951,372			3,951,372
30a	LESS ATTACHMENT MM ADJUSTMENT [Attachment MM, page 2, line 3, column 14] (Note CC) [Revenue Requirement for facilities included on page 2, line 2, and also included in Attachment MM]		71,598,897			71,598,897
30b	LESS EL17-10 ADJUSTMENT (effective October 1, 2016) (Note HH)		1,750,000			1,750,000
31	REV. REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT O (line 29 - line 30 - line 30a - line 30b)		626,615,822			128,992,628

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2020

Northern Indiana Public Service Company LLC

SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN ISO RATES		
1	Total transmission plant (page 2, line 2, column 3)		1,840,513,632
2	Less transmission plant excluded from ISO rates (Note M)		0
3	Less transmission plant included in OATT Ancillary Services (Note N)		0
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)		1,840,513,632
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	**1.00000**
	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		56,429,251
7	Less transmission expenses included in OATT Ancillary Services (Note L)		3,935,799
8	Included transmission expenses (line 6 less line 7)		52,493,452
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		0.93025
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	1.00000
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	**0.93025**

Line No.	WAGES & SALARY ALLOCATOR (W&S)	Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	Production	354.20.b	45,572,183	0.00	0			
13	Transmission	354.21.b	12,483,448	1.00	12,483,448			
14	Distribution	354.23.b	20,469,264	0.00	0			
15	Other	354.24, 25, 26.b	7,927,121	0.00	0			
16	Total (sum lines 12-15)		86,452,016		12,483,448	=	**0.14440**	= WS

Line No.	COMMON PLANT ALLOCATOR (CE) (Note O)		$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	7,159,621,213					
18	Gas		0	1.00000	*	0.14440	=	**0.14440**
19	Water		0					
20	Total (sum lines 17 - 19)		7,159,621,213					

Line No.	RETURN (R)			$
21		Long Term Interest (117, sum of 62.c through 67.c)		$119,022,777
22		Preferred Dividends (118.29c) (positive number)		$ -
	Development of Common Stock:			
23		Proprietary Capital (112.16.c) (Note AA)		3,165,704,591
24		Less Preferred Stock (line 28) (Note AA)		0
25		Less Account 216.1 (112.12.c) (enter negative) (Note AA)		-38,526,568
26		Common Stock	(sum lines 23-25)	3,127,178,023

Line No.		$	%	Cost (Note P)	Weighted	
27	Long Term Debt (112, sum of 18.c through 21.c) (Note AA)	2,357,500,000	43%	0.0505	0.0217	=WCLTD
28	Preferred Stock (112.3.c) (Note AA)	0	0%	0.0000	0.0000	
29	Common Stock (line 26) (Note AA)	3,127,178,023	57%	0.1052	0.0600	
30	Total (sum lines 27-29)	5,484,678,023			0.0817	=R

Line No.	REVENUE CREDITS			
	ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note Q)	Load
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			0
32	b. Bundled Sales for Resale included in Divisor on page 1			0
33	Total of (a)-(b)			0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			$0
	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) (Note U)	(330.x.n)		
35	a. Transmission charges for all transmission transactions			$91,234,466
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1			$13,496,597
36a	c. Transmission charges from Schedules associated with Attachment GG (Note X)			$3,951,372
36b	d. Transmission charges from Schedules associated with Attachment MM (Note DD)			$71,598,897
37	Total of (a)-(b)-(c)-(d)			$2,187,600

Northern Indiana Public Service Company LLC

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter

A Peak as would be reported on page 401b, column d of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

B Labeled LF, LU, IF, IU on pages 310-311 of Form 1at the time of the applicable pricing zone coincident monthly peaks.

C Labeled LF on page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

D Labeled LF on page 328 of Form 1 at the time of the applicable pricing zone coincident monthly peaks.

E The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to ASC 740. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against operating income as discussed in Note K. Account 281 is not allocated. The calculation of ADIT in the annual projection amd Annual True-Up calculations will be performed in accordance with Treasury regulation Section 1.167(l)-1(h)(6). Differences attributable to under-projection of ADIT in the annual projection will result in an adjustment to the projected prorated ADIT activity by the difference between the projected monthly activity and the actual monthly activity. However, when projected monthly ADIT activity is an increase and actual monthly ADIT activity is a decrease, actual monthly ADIT activity will be used. Likewise, when projected monthly ADIT activity is a decrease and actual monthly ADIT activity is an increase, actual monthly ADIT activity will be used. Work papers supporting the ADIT calculations will be posted with each Annual True-Up and or Projected Net Revenue Requirement and included in the annual Informational Filing submitted to the Commission. The Annual True-Up or Projected Net Revenue Requirement ADIT worksheets set forth the calculation pursuant to Treasury regulation Section 1.167(l)-1(h)(6). Beginning with the 2020 rate year, the Annual True-Up for a given year will use the same methodology that was used to project that year's rates.

G Identified in Form 1 as being only transmission related balances.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111, line 57 in the Form 1.

I Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:	FIT =	21.00%	
	SIT=	5.375%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O NIPSCO is a combined gas and electric company and does have common plant assets. As all common plant balances and related depreciation expenses are allocated to either gas or electric plant on page(s) 356 of FERC Form 1 using ratios approved by the state jurisdiction, NIPSCO has not included a balance for gas assets in lines 5 and 11 of page 2 nor gas expenses in lines 6 and 11 of page 3. Therefore, there is no need to populate line 18 on page 4 as the gas plant balances and expenses have been eliminated from amounts reported in this Attachment O.

P Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ~~ROE will be supported in the original filing~~ The allowed base ROE shall be established by FERC and no change in ROE may be made absent a filing with FERC. A 50 basis point adder for RTO participation may be added to the ROE up to the upper end of the zone of reasonableness established by FERC.

Q Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4, page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.

T The revenues credited on page 1, lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

U Account 456.1 entry shall be the annual total of the quarterly values reported at Form 1, 330.x.n.

V Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.

W Pursuant to Attachment GG of the MISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment GG.

X Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment GG of the MISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment GG revenue requirements.

Y Page 2, line 23a includes any unamortized balances related to the recovery of abandoned plant costs approved by FERC. Page 3, line 9a includes the Amortization expense of abandonment plant costs approved by FERC. These are shown in the workpapers required pursuant to the Annual Rate Calculation and True-Up Procedures.

Z Calculate using 13 month average balance, reconciling to FERC Form No. 1 by page, line and column as shown in Column 2.

AA For items not subject to proration under Note F, ~~C~~calculate using a simple average of beginning of year and end of year balances reconciling to FERC Form No. 1 by page, line and column as shown in Column 2.

BB Calculation of Prior Year Divisor True-Up:

Historic Year Actual Divisor	Pg 1, Line 15	2,899,500
Projected Year Divisor	Pg 1, Line 15	2,803,455
Difference between Historic & Project Yr Divisor		96,045

Prior Year Projected Annual Cost ($ per kw per yr.)	Pg 1, Line 16	38.70100
Projected Year Divisor True-up (Difference * Prior Year Projected Annual Cost)		(3,717,054)

CC Pursuant to Attachment MM of the MISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment MM.

DD Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment MM of the MISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment MM revenue requirements.

EE Schedule 10-FERC charges should not be included in O&M recovered under this Attachment O.

FF Stores Expense Undistributed (Account 163) will be the average of the beginning of the year and the end of year balances, multiplied by the "Ratio O&M" percentage for electric, as reported on page(s) 356 of the Form 1, multiplied by the Net Plant (NP) Allocator, as calculated on page 2, line 18, column 4 of this Attachment O.

GG Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.

HH NIPSCO agrees to provide an annual Attachment O adjustment pursuant to Docket No. EL17-10 until NIPSCO files for new Attachment O depreciation rates. For the first year of this adjustment, NIPSCO will prorate the adjustment based on the effective date for the EL17-10 depreciation rates. To the extent NIPSCO files for new Attachment O depreciation rates with an effective date other than January 1 of a particular year, NIPSCO will likewise prorate the adjustment to cover only the portion of the year covered by the EL17-10 depreciation rates.

II Includes the amortization of any excess/deficient deferred income taxes resulting from changes to income tax laws, income tax rates (including changes in apportionment) and other actions taken by a taxing authority. Excess and deficient deferred income taxes will reduce or increase tax expense by the amount of the excess or deficiency multiplied by (1/(1-T)) (page 3, line 26a).

JJ Includes the annual income tax cost or benefits due to permanent differences or differences between the amount of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction. T multiplied by the amount of permanent differences and depreciation expense associated with Allowance for Other Funds Used During Construction is included in page 3, line 24b and will increase or decrease tax expense by the amount of the expense or benefit included on line 24b multiplied by (1/(1-T)) (page 3, line 26b).

Northern Indiana Public Service Company LLC
Plant in Service
Budgeted for the period ending December 2019 through December 2020

Gross Plant in Service

	Electric Plant				Common
				General	Allocated to
	Production	Transmission	Distribution	&Intangible	Electric
December-19	$ 4,047,619,710	$ 1,785,762,323	$ 2,230,935,085	$ 161,314,680	$ 269,848,397
January-20	4,055,148,135	1,794,178,979	2,244,132,430	161,689,846	269,951,608
February-20	4,063,504,646	1,802,985,811	2,256,790,239	162,060,202	270,057,045
March-20	4,071,964,182	1,812,125,083	2,268,950,734	162,440,048	270,174,156
April-20	4,079,457,794	1,821,307,674	2,280,579,194	162,841,871	270,289,500
May-20	4,085,874,404	1,830,654,539	2,291,893,462	163,257,698	270,393,508
June-20	4,092,639,959	1,839,938,635	2,303,196,221	163,684,149	270,493,488
July-20	4,099,470,966	1,849,722,194	2,314,521,205	164,094,873	270,581,906
August-20	4,106,483,282	1,859,669,225	2,326,339,446	164,481,999	270,670,769
September-20	4,112,699,706	1,869,135,062	2,338,422,326	164,874,814	270,759,616
October-20	4,117,999,728	1,878,387,168	2,350,944,247	165,269,925	270,850,177
November-20	4,123,288,626	1,887,050,556	2,363,729,011	165,687,031	270,940,516
December-20	4,129,649,163	1,895,759,964	2,376,337,360	166,106,342	271,032,055
13 month Average	$ 4,091,215,408	$ 1,840,513,632	$ 2,303,597,766	$ 163,677,191	$ 270,464,826

Accumulated Depreciation & Amortization

	Electric Plant				Common
				General	Allocated to
	Production	Transmission	Distribution	&Intangible	Electric
December-19	$ 2,057,978,824	$ 572,298,749	$ 1,022,782,839	$ 118,228,384	$ 196,861,736
January-20	2,070,229,636	575,277,361	1,026,049,824	118,362,863	198,192,423
February-20	2,082,412,780	578,231,066	1,029,445,125	118,498,657	199,523,233
March-20	2,094,611,497	581,167,136	1,032,959,938	118,633,237	200,852,509
April-20	2,106,944,891	584,118,422	1,036,599,141	118,764,412	202,182,683
May-20	2,119,422,181	587,071,581	1,040,322,959	118,893,615	203,515,434
June-20	2,131,881,447	590,052,199	1,044,077,187	119,021,461	204,849,416
July-20	2,144,355,315	592,997,669	1,047,855,844	119,152,612	206,185,938
August-20	2,156,831,125	595,946,418	1,051,575,863	119,288,439	207,522,823
September-20	2,169,418,040	598,970,433	1,055,278,825	119,423,743	208,860,155
October-20	2,182,126,878	602,038,942	1,058,934,617	119,559,131	210,197,629
November-20	2,194,854,089	605,193,142	1,062,575,434	119,691,129	211,535,595
December-20	2,207,479,329	608,361,216	1,066,279,451	119,823,257	212,873,800
13 month Average	$ 2,132,195,849	$ 590,132,641	$ 1,044,210,542	$ 119,026,226	$ 204,857,952

Northern Indiana Public Service Company LLC
FERC APPROVED CWIP
Budgeted for the period ending December 2019 through December 2020

		Reynolds to Burr Oak to Hiple 345 kV transmission line (MISO Project 12)		Reynolds to Greentown 765 kV transmission line (MISO Project 14)	
	Total CWIP	Total CWIP	Monthly Budgeted CapEx	Total CWIP	Monthly Budgeted CapEx
December-19	-	-		-	
January-20	-	-	-	-	-
February-20	-	-	-	-	-
March-20	-	-	-	-	-
April-20	-	-	-	-	-
May-20	-	-	-	-	-
June-20	-	-	-	-	-
July-20	-	-	-	-	-
August-20	-	-	-	-	-
September-20	-	-	-	-	-
October-20	-	-	-	-	-
November-20	-	-	-	-	-
December-20	-	-	-	-	-
13 month Average	-	-		-	

Northern Indiana Public Service Company
Adjustments to Rate Base
Average of Beginning and End of Year Balance

	281	282	283	190	255
Gross Accumulated Deferred Income Taxes					
Beginning of Year - Non Prorated Items	$ -	$ 266,966,706	$ 91,763,681	$ 160,086,218	$ 41,233
January					
February					
March					
April					
May					
June					
July					
August					
September					
October					
November					
End of Year - Non Prorated Items	-	285,336,773	91,763,681	148,571,155	-
BOY/EOY Average - Non Prorated Items	$ -	$ 276,151,739	$ 91,763,681	$ 154,328,687	$ 20,617
Plus Prorated Items	-	483,658,221	-	76,570,201	-
Less ASC 740 Regulatory Assets or Liabilities	-	(421,721,739)	-	73,407	-
Amount for Attachment O	$ -	$ 1,181,531,699	$ 91,763,681	$ 230,825,481	$ 20,617

Northern Indiana Public Service Company LLC
Accumulated Deferred Income Taxes
Year Ended December 31, 2020

Rate Year = *Projected 2020*

1 **Account 190**

2	Days in Period					Averaging with Proration - Projected		
	A	B	C	D	E	F	G	H
3	Month	Days in the Month	Number of Days Remaining in Year After Month's Accrual of Deferred Taxes	Total Days in Future Portion of Test Period (Line 18, Col B)	Proration Amount (Lines 6 to 17, Col C / Col D)	Projected Monthly Activity	Prorated Projected Monthly Activity (Lines 6 to 17, Col E x Col F)	Prorated Projected Balance (Line 5, Col H plus Cumulative Sum of Col G)
4								
5	December 31st balance Prorated Items (FF1 234.8.b less non Prorated Items)							81,746,585
6	January	31	336	366	91.80%	(933,279)	(856,781)	80,889,804
7	February	29	307	366	83.88%	(933,279)	(782,832)	80,106,972
8	March	31	276	366	75.41%	(933,279)	(703,784)	79,403,188
9	April	30	246	366	67.21%	(933,279)	(627,286)	78,775,902
10	May	31	215	366	58.74%	(933,279)	(548,238)	78,227,664
11	June	30	185	366	50.55%	(933,279)	(471,739)	77,755,925
12	July	31	154	366	42.08%	(933,279)	(392,691)	77,363,233
13	August	31	123	366	33.61%	(933,279)	(313,643)	77,049,591
14	September	30	93	366	25.41%	(933,279)	(237,145)	76,812,446
15	October	31	62	366	16.94%	(933,279)	(158,096)	76,654,349
16	November	30	32	366	8.74%	(933,279)	(81,598)	76,572,751
17	December	31	1	366	0.27%	(933,279)	(2,550)	76,570,201
18	Total (sum of lines 6-17)	366				(11,199,348)	(5,176,384)	

19	Beginning Balance	234.8.b	241,832,803
20	Less non Prorated Items (non Property-related) items	(Line 19 less line 21)	160,086,218
21	Beginning Balance of Prorated items	(Line 5, Col H)	81,746,585
22	Ending Balance	234.8.c	225,141,357
23	Less non Prorated (non Property-related) Items	(Line 22 less line 24)	148,571,155
24	Ending Balance of Prorated items	(Line 17, Col H)	76,570,201
25	Average Balance (See Note 6.)	Line 24 Col H + (Lines 20 + 23 Col H)/2	230,898,888
26	Less ASC 740 Items	Attachment O, Footnote F	73,407
27	Amount for Attachment O, Page 2, Line 22	(Line 25 less line 26)	**230,825,481**

28 **Account 282**

29	Days in Period					Averaging with Proration - Projected		
	A	B	C	D	E	F	G	H
30	Month	Days in the Month	Number of Days Remaining in Year After Month's Accrual of Deferred Taxes	Total Days in Future Portion of Test Period (Line 45, Col B)	Proration Amount (Lines 33 to 44, Col C / Col D)	Projected Monthly Activity	Prorated Projected Monthly Activity (Lines 33 to 44, Col E x Col F)	Prorated Projected Balance (Line 32, Col H plus Cumulative Sum of Col G)
31								
32	December 31st balance Prorated Items (FF1 234.8.b less non Prorated Items)							488,014,013
33	January	31	336	366	91.80%	(785,330)	(720,959)	487,293,054
34	February	29	307	366	83.88%	(785,330)	(658,733)	486,634,321
35	March	31	276	366	75.41%	(785,330)	(592,216)	486,042,105
36	April	30	246	366	67.21%	(785,330)	(527,845)	485,514,260
37	May	31	215	366	58.74%	(785,330)	(461,328)	485,052,933
38	June	30	185	366	50.55%	(785,330)	(396,956)	484,655,976
39	July	31	154	366	42.08%	(785,330)	(330,439)	484,325,537
40	August	31	123	366	33.61%	(785,330)	(263,922)	484,061,614
41	September	30	93	366	25.41%	(785,330)	(199,551)	483,862,063
42	October	31	62	366	16.94%	(785,330)	(133,034)	483,729,029
43	November	30	32	366	8.74%	(785,330)	(68,663)	483,660,367
44	December	31	1	366	0.27%	(785,330)	(2,146)	483,658,221
45	Total (sum of lines 33-44)	366				(9,423,960)	(4,355,792)	

46	Beginning Balance	274.2.b	754,980,719
47	Less non Prorated Items (non Property-related) items	(Line 46 less line 48)	266,966,706
48	Beginning Balance of Prorated items	(Line 32, Col H)	488,014,013
49	Ending Balance	275.2.k	768,994,993
50	Less non Prorated (non Property-related) Items	(Line 49 less line 51)	285,336,773
51	Ending Balance of Prorated items	(Line 44, Col H)	483,658,221
52	Average Balance (See Note 6.)	Line 51 Col H + (Lines 47 + 50 Col H)/2	759,809,960
53	Less ASC 740 Items	Attachment O, Footnote F	(421,721,739)
54	Amount for Attachment O, Page 2, Line 20	(Line 52 less line 53)	**1,181,531,699**

Line	A	B	C	D	E	F	G	H
55	**Account 283**							
56			**Days in Period**				**Averaging with Proration - Projected**	
	A	B	C	D	E	F	G	H
57	Month	Days in the Month	Number of Days Remaining in Year After Month's Accrual of Deferred Taxes	Total Days in Future Portion of Test Period (Line 72, Col B)	Proration Amount (Lines 60 to 71, Col C / Col D)	Projected Monthly Activity	Prorated Projected Monthly Activity (Lines 60 to 71, Col E x Col F)	Prorated Projected Balance (Line 59, Col H plus Cumulative Sum of Col G)
58								
59	December 31st balance Prorated Items (FF1 234.8.b less non Prorated Items)							-
60	January	31	336	366	91.80%	-	-	-
61	February	29	307	366	83.88%	-	-	-
62	March	31	276	366	75.41%	-	-	-
63	April	30	246	366	67.21%	-	-	-
64	May	31	215	366	58.74%	-	-	-
65	June	30	185	366	50.55%	-	-	-
66	July	31	154	366	42.08%	-	-	-
67	August	31	123	366	33.61%	-	-	-
68	September	30	93	366	25.41%	-	-	-
69	October	31	62	366	16.94%	-	-	-
70	November	30	32	366	8.74%	-	-	-
71	December	31	1	366	0.27%	-	-	-
72	Total (sum of lines 60-71)	366				-	-	
73	Beginning Balance				276.9.b			91,763,681
74	Less non Prorated Items (non Property-related) items				(Line 73 less line 75)			91,763,681
75	Beginning Balance of Prorated items				(Line 59, Col H)			-
76	Ending Balance				277.9.k			91,763,681
77	Less non Prorated (non Property-related) Items				(Line 76 less line 78)			91,763,681
78	Ending Balance of Prorated items				(Line 71, Col H)			-
79	Average Balance (See Note 6.)				Line 78 Col H + (Lines 74 + 77 Col H)/2			91,763,681
80	Less ASC 740 Items				Attachment O, Footnote F			
81	Amount for Attachment O, Page 2, Line 21				(Line 79 less line 80)			**91,763,681**

NOTES

1) Column J is the difference between projected monthly and actual monthly activity (Column I minus Column F). Specifically, if projected and actual activity are both positive, a negative in Column J represents over-projection (amount of projected activity that did not occur) and a positive in Column J represents under-projection (excess of actual activity over projected activity). If projected and actual activity are both negative, a negative in Column J represents under-projection (excess of actual activity over projected activity) and a positive in Column J represents over-projection (amount of projected activity that did not occur).

2) Column K preserves proration when actual monthly and projected monthly activity are either both increases or decreases. Specifically, if Column J is over-projected, enter Column G x [Column I/Column F]. If Column J is under-projected, enter the amount from Column G and complete Column L). In other situations, enter zero.

3) Column L applies when (1) Column J is under-projected AND (2) actual monthly and projected monthly activity are either both increases or decreases. Enter the amount from Column J. In other situations, enter zero.

4) Column M applies when (1) projected monthly activity is an increase while actual monthly activity is a decrease OR (2) projected monthly activity is a decrease while actual monthly activity is an increase. Enter actual monthly activity (Col I). In other situations, enter zero.

5) Column N is computed by adding the prorated monthly activity, if any, from Column K to 50 percent of the portion of monthly activity, if any, from Column L or M to the balance at the end of the prior month. The activity in columns L and M is multiplied by 50 percent to reflect averaging of rate base to the extent that the proration requirement has not been applied to a portion of the monthly activity.

6) For the non-property-related component of the balance, the Average Balance is computed using the average of beginning of year and end of year balance. For the property-related component of the balance, the Average Balance is computed as described in Note 5.

Northern Indiana Public Service Company LLC
Land Held for Future Use (Balances at beginning of year and end of year)
Average of Beginning and End of Year Balance

Land Held for Future Use (Balances at beginning of year and end of year)

		Account 105*
December-19	$	3,380,616
January-20		-
February-20		-
March-20		-
April-20		-
May-20		-
June-20		-
July-20		-
August-20		-
September-20		-
October-20		-
November-20		-
December-20		3,380,616
BOY/EOY Average	$	3,380,616

* Only Land Held for Future Use that is Transmission Related. Excludes Land Held for Future Use for MVP projects, as balance is included in FERC Approved CWIP

Northern Indiana Public Service Company LLC
Materials & Supplies
Average of Beginning and End of Year Balance

Source: Footnote to FERC Form 1, 227.8.c & .16.c

		FERC 163 Common Electric & Gas		FERC 163 Common Allocated to Electric [a]		FERC 163 Electric Allocated to Transmission [b]		FERC 154 Transmission Plant		Total
December-19	$	7,251,535	$	-	$	-	$	37,649,722		
January-20										
February-20										
March-20										
April-20										
May-20										
June-20										
July-20										
August-20										
September-20										
October-20										
November-20										
December-20		7,251,535		-		-		37,649,722		
BOY/EOY Average	$	7,251,535	$	5,348,732	$	1,479,153	$	37,649,722	$	37,649,722

(a) allocated using Ratio H reported on page 356.1 of FERC Form 1: 73.76%
(b) allocated using the Net Plant (NP) allocator reported on page 2 line 18 column 4 : 27.65%

Northern Indiana Public Service Company LLC
Prepayments
Average of Beginning and End of Year Balance

Working Capital (Balances at beginning of year and end of year)
Source: Footnote to FERC Form 1, 111.57.c

		Prepayments
December-19	$	30,210,907
January-20		-
February-20		-
March-20		-
April-20		-
May-20		-
June-20		-
July-20		-
August-20		-
September-20		-
October-20		-
November-20		-
December-20		30,210,907
BOY/EOY Average	$	30,210,907

Northern Indiana Public Service Company LLC
Transmission Expenses
Budgeted for the period ending December 31, 2020

Account Number			December-20
	OPERATION		
560.0	Supervision and Engineering	$	1,633,262
561.0	Load Dispatching		-
561.1	Load Dispatching - Reliability		2,068,823
561.2	Load Dispatching -Monitor & Operate Transmission System		1,866,976
561.3	Load Dispatching- Transmission Service & Scheduling		-
561.4	Scheduling, System Control & Dispatch Service		262,734
561.5	Reliability, Planning and Standards Development		714,656
561.6	Transmission Service Studies		-
561.7	General Interconnection Studies		-
561.8	Reliability, Planning and Standards Development Services		-
561.81	RECB Network Upgrade Charges		33,835,300
562.0	Station Expense		997,216
563.0	Overhead Line Expense		145,260
565.0	Transmission of Electricity by Others		-
566.0	Miscellaneous Transmission Expenses		1,096,381
567.0	Rents		-
	Total Operation	$	42,620,608
	MAINTENANCE		
568.0	Supervision and Engineering	$	1,711,642
569.0	Structures		-
569.1	Computer Hardware		257,657
569.2	Computer Software		1,119,988
569.3	Communication Equipment		-
570.0	Station Equipment		6,830,096
571.0	Overhead Lines		4,176,428
573.0	Miscellaneous Transmission Plant		24,363
	Total Maintenance	$	14,120,174
	Total Operations and Maintenance before TUA Credit	$	56,740,782
	Credit for TUA [1]	$	(311,531)
	Total Operations and Maintenance including TUA Credit	$	56,429,251

[1] The TUA credit represents amounts collected for operation and maintenance of system upgrades constructed under Transmission Upgrade Agreements (TUAs).

Northern Indiana Public Service Company LLC
Administrative and General Expenses
Budgeted for the period ending December 31, 2020

	Account Number			December-20
		ADMINISTRATIVE AND GENERAL EXPENSES		
	920.0	Administrative and General Salaries	$	65,897,478
	921.0	Office Supplies and Expenses		23,969,655
Less	922.0	Administrative Expenses Transferred- Credit		-
	923.0	Outside Services Employed		43,820,072
	924.0	Property Insurance		2,587,109
	925.0	Injuries and Damages		10,209,149
	926.0	Employees Pensions and Benefits		30,068,081
	928.0	Regulatory Commission Expenses		1,211,800
	929.0	(Less) Duplicate Charges - Cr		-
	930.1	General Advertising Expense		34,903
	930.2	Miscellaneous General Expenses		2,945,904
	931.0	Rents		7,769,466
	935.0	Maintenances of General Plant		11,359,711
		Total Administrative and General	$	199,873,328

Ref	EPRI, REG COMMISSION EXPENSE & NON SAFETY ADVERTISING		December-20
a	Electric Power Research Institute	$	715,769
928.0, b	Regulatory Commission Expenses		1,211,800
c	Non-safety Advertisement		34,903
923, d	Regulatory Commission Expenses		664,755
		$	2,627,227

a - Amount of EPRI expense listed in Form 1 at 353.f
b - Only amounts directly related to transmission service, ISO filings, or transmission siting
c - Non-safety advertising included in account 930.1
d - Amount of Regulatory Commission Expense reported in Form 1 at 351.h

Northern Indiana Public Service Company LLC
Depreciation and Amortization
Budgeted for the period ending December 31, 2020

DEPRECIATION EXPENSE		December-20
Transmission	$	48,284,427
General & Intangible	$	2,440,460
Common	$	16,220,945

Northern Indiana Public Service Company LLC
Taxes Other than Income Allocated to Electric
Budgeted for the period ending December 31, 2020

		December-20		TUA Amounts
Payroll [1]	$	10,117,295	$	3,786
Property [1]	$	23,499,231	$	71,937
Gross Receipts	$	24,299,885		
Other	$	-		

[1] These values are net of amounts collected for property and payroll tax of system upgrades constructed under Transmission Upgrade Agreements (TUAs).

Northern Indiana Public Service Company LLC
Wages and Salary / Common Plant Allocator
Budgeted for the period ending December 31, 2020

ELECTRIC WAGES & SALARY ALLOCATOR (W&S)

	December-20
Production	$ 45,572,183
Transmission	$ 12,483,448
Distribution	$ 20,469,264
Other	$ 7,927,121

COMMON PLANT ALLOCATOR

	December-20
Electric	$ 7,159,621,213
Gas	$ -
Water	$ -
	$7,159,621,213

Northern Indiana Public Service Company LLC
Capital Structure
Budgeted for the period ending December 31, 2020

Long-Term Debt		
December-19	$	2,253,500,000
January-20		
February-20		
March-20		
April-20		
May-20		
June-20		
July-20		
August-20		
September-20		
October-20		
November-20		
December-20		2,461,500,000
Average of Beginning and End of Year Balance	$	2,357,500,000
Interest & Preferred Dividend Expense		
Annualized Long-Term Debt Interest Expense	$	119,022,777
Preferred Dividends	$	-
Common Equity		
December-19	$	2,990,472,940
January-20		
February-20		
March-20		
April-20		
May-20		
June-20		
July-20		
August-20		
September-20		
October-20		
November-20		
December-20		3,340,936,241
Average of Beginning and End of Year Balance	$	3,165,704,591
Preferred Stock		
December-19	$	-
January-20		
February-20		
March-20		
April-20		
May-20		
June-20		
July-20		
August-20		
September-20		
October-20		
November-20		
December-20		-
Average of Beginning and End of Year Balance	$	-
Unappropriated Undistributed Subsidiary Earnings		
December-19	$	37,638,044
January-20		
February-20		
March-20		
April-20		
May-20		
June-20		
July-20		
August-20		
September-20		
October-20		
November-20		
December-20		39,415,092
Average of Beginning and End of Year Balance	$	38,526,568

Northern Indiana Public Service Company LLC
Monthly Peaks and Output in (Mw)

DIVISOR
Monthly Peaks and Output in (Mw)
Year Ended December 31, 2020

	NIPSCO Internal	Wholesale
January	2,240	232
February	2,151	242
March	2,159	267
April	2,038	259
May	2,431	313
June	2,736	356
July	2,929	402
August	2,913	395
September	2,687	337
October	2,108	269
November	2,101	243
December	2,196	238
Total	28,690	3,553
Average (Mw)	2,390.81	296.06
Average (kWh)	2,390,813	296,062

Northern Indiana Public Service Company LLC

Account 456.1 (Other Electric Revenues)
Year Ended December 31, 2020

Transmission of Electricity for Others (Account 456.1)

Transmission Charges for Transmission Transactions		December-20	
Midwest ISO (Schedule 7&8)	$	1,569,600	
Midwest ISO (Schedule 9)		2,464,770	
Midwest ISO (Schedule 26)		2,461,186	
Midwest ISO (Schedule 26-a)		71,598,897	(a)
Midwest ISO (Schedule 26-c)		1,490,186	
Indiana Municipal Power Agency		346,085	
Wabash Valley Power Authority		10,536,535	
Midwest ISO (Schedule 1)		208,434	
Midwest ISO (Schedule 2)		558,773	
Midwest ISO (Schedule 24)		-	
Total Account 456.1 Charges	$	91,234,466	
Less: Schedule 1 (related to Schedule 9)	$	71,634	
Less: Schedule 2 (related to Schedule 9)		77,573	
Less: Schedule 9		2,464,770	
Less: Schedule 24		-	
Less: Schedule 26		2,461,186	
Less: Schedule 26-a		71,598,897	
Less: Midwest ISO (Schedule 26-c)		1,490,186	
Indiana Municipal Power Agency		346,085	
Wabash Valley Power Authority		10,536,535	
Total Revenue Credit	$	2,187,600	

[a] Schedule 26a revenue received; excludes true-up accruals, reversals, and other revenue adjustments

Northern Indiana Public Service Company LLC

Adjustments to the Provision for Income Tax
Year Ended December 31, 2020

Reversal Normalized				
	Depreciation	$	21,248,109	
	COR		-	
		$	21,248,109	
Reversal Flow Thru				
	AFUDC Equity	$	(3,629,795)	
	Method Life		(20,517,460)	
		$	(24,147,255)	
Bonus		$	102,862,812	
		$	102,862,812	
Plant Temporary Difference		$	99,963,666	
APB11 Deferreds				
Reversal Excess Deferred		$	(5,036,285)	
Reversal Flow Thru		$	-	
Bonus		$	-	
FAS109 Deferreds				
Reversal Excess Deferred		$	5,284,617	
Reversal Flow Thru		$	(6,005,664)	
Bonus		$	3,981,819	
Flow Thru & Excess				
Reversal Excess Deferred		$	10,320,902	
Reversal FT			(6,005,664)	
Bonus			3,981,819	
	Total Flow Thru & Excess	$	8,297,057	
	Method Life FT	$	(5,102,898)	
	ARAM (Excess)	$	14,302,721	
	ITC	$	-	
	Treasury Grant		-	
	Non-Plant		-	
	Other, including ARAM	$	(9,199,823)	
		$	(9,199,823)	Page 3, Line 24a
	AFUDC Equity	$	902,766	
	Other Permanent Differences		-	
		$	902,766	Page 3, Line 24b
	Net Reversals	$	(8,297,057)	

Formula Rate calculation

Rate Formula Template
Utilizing Attachment O Data

Northern Indiana Public Service Company LLC

To be completed in conjunction with Attachment O.

Line No.	(1)	(2) **Attachment O Page, Line, Col.**	(3) **Transmission**	(4) **Allocator**
1	Gross Transmission Plant - Total	Attach O, p 2, line 2 col 5 (Note A)	1,840,513,632	
2	Net Transmission Plant - Total	Attach O, p 2, line 14 and 23b col 5 (Note B)	1,250,380,991	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach O, p 3, line 8 col 5	46,877,246	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	2.55%	2.55%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Attach O, p 3, lines 10 & 11, col 5 (Note H)	2,694,659	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.15%	0.15%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach O, p 3, line 20 col 5	6,619,682	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1 col 3)	0.36%	0.36%
9	**Annual Allocation Factor for Expense**	**Sum of line 4, 6, and 8**		**3.05%**
	INCOME TAXES			
10	Total Income Taxes	Attach O, p 3, line 27 col 5	17,773,415	
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2 col 3)	1.42%	1.42%
	RETURN			
12	Return on Rate Base	Attach O, p 3, line 28 col 5	84,043,469	
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2 col 3)	6.72%	6.72%
14	**Annual Allocation Factor for Return**	**Sum of line 11 and 13**	**8.14%**	**8.14%**

Attachment GG
For the 12 months ended 12/31/2020

Formula Rate calculation

Rate Formula Template
Utilizing Attachment O Data

Northern Indiana Public Service Company LLC

Network Upgrade Charge Calculation By Project

Line No.	(1) Project Name	(2) MTEP Project Number	(3) Project Gross Plant	(4) Annual Allocation Factor for Expense	(5) Annual Expense Charge	(6) Project Net Plant	(7) Annual Allocation Factor for Return	(8) Annual Return Charge	(9) Project Depreciation Expense	(10) Annual Revenue Requirement	(11) True-Up Adjustment	(12) Network Upgrade Charge
			(Note C)	(Page 1 line 9)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 14)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a	MTEP07	612	$ 5,775,282	3.05%	$ 176,322	$ 4,026,421	8.14%	$ 327,866	$ 158,679	$ 662,867	$ (115,319)	$ 547,548
1b	MTEP08	1551	$ 4,410,237	3.05%	$ 134,646	$ 2,959,387	8.14%	$ 240,979	$ 136,535	$ 512,160	$ (89,093)	$ 423,067
1c	MTEP07	1615 GIP	$ 818,471	3.05%	$ 24,988	$ 1,643,195	8.14%	$ 133,803	$ 22,092	$ 180,883	$ (123,000)	$ 57,883
1d	MTEP11	2322	$ 9,263,742	3.05%	$ 282,826	$ 6,971,641	8.14%	$ 567,692	$ 254,759	$ 1,105,276	$ (189,623)	$ 915,653
2	Annual Totals									$ 2,461,186	$ (517,035)	$ 1,944,151
3	NUC and TMEPC Rev. Req. Adj For Attachment O (Attachment GG page 2, line 2, Column 10 plus Attachment GG, page 3, line 2, Column 10)									$3,951,372		

Note Letter

A Gross Transmission Plant is that identified on Page 2 Line 2 of Attachment O and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order less any prefunded AFUDC, if applicable.

B Net Transmission Plant is that identified on Page 2 Line 14 of Attachment O and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order less any prefunded AFUDC, if applicable.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in Line 1 and includes CWIP in rate base less any prefunded AFUDC, if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.

E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment O Page 3 Line 12.

F True-Up Adjustment is included pursuant to a FERC approved methodology, if applicable.

G The Targeted Market Efficiency Project Charge is the value to be used in Schedule 26-C.

H The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 3 column 9.

Formula Rate calculation

Rate Formula Template
Northern Indiana Public Service Company LLC

Utilizing Attachment O Data

Targeted Market Efficiency Project Charge Calculation By Project

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line Efficiency No. Charge	Project Name	MTEP Project Number	Project Gross Plant	Annual Allocation Factor for Expense	Annual Expense Charge	Project Net Plant	Annual Allocation Factor for Return	Annual Return Charge	Project Depreciation Expense	Annual Revenue Requirement	True-Up Adjustment	Targeted Market Project
			(Note C)	(Page 1 line 9)	(Col. 3 * Col. 4)	(Note D)	(Page 1 line 14)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Sum Col. 10 & 11 (Note G)
1a	MTEP17	14267	$ 75,877	3.05%	$ 2,317	$ 75,355	8.14%	$ 6,136	$ 1,938	$ 10,391	$ -	$ 10,391
1b	MTEP17	14264	$ 3,776,257	3.05%	$ 115,291	$ 3,753,311	8.14%	$ 305,627	$ 85,229	$ 506,147	$ -	$ 506,147
1c	MTEP17	14266	$ 3,687,369	3.05%	$ 112,577	$ 3,668,016	8.14%	$ 298,682	$ 71,881	$ 483,140	$ -	$ 483,140
1d	MTEP17	14268	$ 3,880,304	3.05%	$ 118,467	$ 3,864,869	8.14%	$ 314,711	$ 57,330	$ 490,508	$ -	$ 490,508
2	Annual Totals									$1,490,186	$0	$1,490,186

Note Letter	
A	Gross Transmission Plant is that identified on Page 2 Line 2 of Attachment O and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order less any prefunded AFUDC, if applicable.
B	Net Transmission Plant is that identified on Page 2 Line 14 of Attachment O and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order less any prefunded AFUDC, if applicable.
C	Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in Line 1 and includes CWIP in rate base less any prefunded AFUDC, if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.
D	Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.
E	Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment O Page 3 Line 12.
F	True-Up Adjustment is included pursuant to a FERC approved methodology, if applicable.
G	The Targeted Market Efficiency Project Charge is the value to be used in Schedule 26-C.
H	The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 3 column 9.

Attachment GG - Supporting Data for Network Upgrade Charge Calculation - Forward Looking Rate Transmission Owner

Rate Year 2020

Reporting Company Northern Indiana Public Service Company LLC

	MTEP Project ID	612	1551	1615 GIP	2322	14267	14264	14266	14268
	Pricing Zone	East - NIPS	East	East - NIPS	East	East - NIPS	East - NIPS	East - NIPS	East - NIPS
	Allocation Type Per Attachment FF	Reliability	Reliability	GIP	Reliability	TMEP	TMEP	TMEP	TMEP
Gross Plant	December 2019	$ 5,775,282	$ 4,410,237	$ 818,471	$ 9,263,742	-	-	-	-
Column (3)	January 2020	5,775,282	4,410,237	818,471	9,263,742	-	-	-	-
	February	5,775,282	4,410,237	818,471	9,263,742	-	-	-	-
	March	5,775,282	4,410,237	818,471	9,263,742	-	-	-	-
	April	5,775,282	4,410,237	818,471	9,263,742	-	-	-	-
	May	5,775,282	4,410,237	818,471	9,263,742	-	-	-	-
	June	5,775,282	4,410,237	818,471	9,263,742	140,914	7,013,049	6,847,971	7,206,279
	July	5,775,282	4,410,237	818,471	9,263,742	140,914	7,013,049	6,847,971	7,206,279
	August	5,775,282	4,410,237	818,471	9,263,742	140,914	7,013,049	6,847,971	7,206,279
	September	5,775,282	4,410,237	818,471	9,263,742	140,914	7,013,049	6,847,971	7,206,279
	October	5,775,282	4,410,237	818,471	9,263,742	140,914	7,013,049	6,847,971	7,206,279
	November	5,775,282	4,410,237	818,471	9,263,742	140,914	7,013,049	6,847,971	7,206,279
	December 2020	5,775,282	4,410,237	818,471	9,263,742	140,914	7,013,049	6,847,971	7,206,279
	13 Month Average	$ 5,775,282	$ 4,410,237	$ 818,471	$ 9,263,742	$ 75,877	$ 3,776,257	$ 3,687,369	$ 3,880,304

Accumulated	December 2019	$ 1,669,521	$ 1,382,583	$ (835,770)	$ 2,164,722	-	-	-	-
Depreciation	January 2020	1,682,744	1,393,961	(833,929)	2,185,952	-	-	-	-
	February	1,695,967	1,405,339	(832,088)	2,207,182	-	-	-	-
	March	1,709,191	1,416,716	(830,247)	2,228,412	-	-	-	-
	April	1,722,414	1,428,094	(828,406)	2,249,642	-	-	-	-
	May	1,735,637	1,439,472	(826,565)	2,270,872	-	-	-	-
	June	1,748,860	1,450,850	(824,724)	2,292,102	-	-	-	-
	July	1,762,084	1,462,228	(822,883)	2,313,331	323	14,205	11,980	9,555
	August	1,775,307	1,473,606	(821,042)	2,334,561	646	28,410	23,960	19,110
	September	1,788,530	1,484,984	(819,201)	2,355,791	969	42,614	35,940	28,665
	October	1,801,753	1,496,362	(817,360)	2,377,021	1,292	56,819	47,920	38,220
	November	1,814,977	1,507,740	(815,518)	2,398,251	1,615	71,024	59,901	47,775
	December 2020	1,828,200	1,519,117	(813,677)	2,419,481	1,938	85,229	71,881	57,330
	13 Month Average	$ 1,748,860	$ 1,450,850	$ (824,724)	$ 2,292,102	$ 522	$ 22,946	$ 19,352	$ 15,435

Net Plant	December 2019	$ 4,105,761	$ 3,027,654	$ 1,654,241	$ 7,099,020	$ -	$ -	$ -	$ -
Column (6)	January 2020	4,092,538	3,016,276	1,652,400	7,077,790	-	-	-	-
	February	4,079,314	3,004,898	1,650,559	7,056,560	-	-	-	-
	March	4,066,091	2,993,520	1,648,718	7,035,330	-	-	-	-
	April	4,052,868	2,982,143	1,646,877	7,014,100	-	-	-	-
	May	4,039,645	2,970,765	1,645,036	6,992,871	-	-	-	-
	June	4,026,421	2,959,387	1,643,195	6,971,641	140,914	7,013,049	6,847,971	7,206,279
	July	4,013,198	2,948,009	1,641,354	6,950,411	140,591	6,998,844	6,835,991	7,196,724
	August	3,999,975	2,936,631	1,639,513	6,929,181	140,268	6,984,640	6,824,011	7,187,169
	September	3,986,752	2,925,253	1,637,672	6,907,951	139,945	6,970,435	6,812,030	7,177,615
	October	3,973,528	2,913,875	1,635,831	6,886,721	139,622	6,956,230	6,800,050	7,168,060
	November	3,960,305	2,902,497	1,633,990	6,865,491	139,299	6,942,025	6,788,070	7,158,505
	December 2020	3,947,082	2,891,119	1,632,149	6,844,261	138,976	6,927,820	6,776,090	7,148,950
	13 Month Average	$ 4,026,421	$ 2,959,387	$ 1,643,195	$ 6,971,641	$ 75,355	$ 3,753,311	$ 3,668,016	$ 3,864,869

Depreciation Expense	Project Depreciation Expense	$ 158,679	$ 136,535	$ 22,092	$ 254,759	$ 1,938	$ 85,229	$ 71,881	$ 57,330
Column (9)	Project Amortization Expense	-	-	-	-	-	-	-	-
	Depreciation Expense Total	$ 158,679	$ 136,535	$ 22,092	$ 254,759	$ 1,938	$ 85,229	$ 71,881	$ 57,330

Attachment GG - Description of Facilities Included in Network Upgrade Charge

MTEP Project ID	Facility ID	Project Record Date	Description of Facilities Included in Network Upgrade Charge as of Record Date
612	1279	MTEP07	Hiple - Add 2nd 345/138 kV Transformer
612	2999	MTEP07	Hiple - Add 2nd 345/138 KV transformer
1551	2650	MTEP08	Flint Lake - Add 2nd 138kV circuit
1615	2667	MTEP07	Benton County - Amount related to 138 kV Ring Bus Interconnection Substation
1615	2668	MTEP07	Benton County - Protection and Relay, 138XX and 138YY Line Extensions 900 MCM ACSR with Static Wire
1615	2665	MTEP07	Benton County - Reconductor/rebuild circuit 6966 to 477 MCM conductor (7.7 mi.)
2322	4248	MTEP11	Green Acres - Install a 560 MVA 345/138 kV transformer, (1) 345 kV and (1) 138 kV circuit breaker and associated equipment
14264	23299	MTEP17	Munster 345 kV Ring Bus - Create a new ring bus at Munster to increase rating on 34504 circuit
14266	23301	MTEP17	Michigan City-Bosserman-Olive - Re-conductor 13813 circuit (10.62 miles)
14267	23002	MTEP17	Reynolds-Magnetation - Upgrade Line Switches to 2000 Amps
14268	23303	MTEP17	Roxana-Praxair - Re-conductor 13835 circuit (2.28 miles)

Formula Rate calculation

Rate Formula Template
Utilizing Attachment O Data

Northern Indiana Public Service Company LLC

To be completed in conjunction with Attachment O.
(inputs from Attachment O are rounded to whole dollars)

Line No.	(1)	(2) Attachment O Page, Line, Col.	(3) Transmission	(4) Allocator
1	Gross Transmission Plant - Total	Attach O, p 2, line 2 col 5 (Note A)	1,840,513,632	
1a	Transmission Accumulated Depreciation	Attach O, p 2, line 8 col 5 (Note J)	590,132,641	
2	Net Transmission Plant - Total	Line 1 minus Line 1a (Note B)	1,250,380,991	
	O&M TRANSMISSION EXPENSE			
3	Total O&M Allocated to Transmission	Attach O, p 3, line 8 col 5	46,877,246	
3a	Transmission O&M	Attach O, p 3, line 1 col 5	52,493,452	
3b	Less: LSE Expenses included in above, if any	Attach O, p 3, line 1a col 5, if any	34,098,034	
3c	Less: Account 565 included in above, if any	Attach O, p 3, line 2 col 5, if any	-	
3d	Adjusted Transmission O&M	Line 3a minus Line 3b minus Line 3c	18,395,418	
4	**Annual Allocation Factor for Transmission O&M**	(Line 3d divided by line 1a, col 3)	**3.12%**	**3.12%**
	OTHER O&M EXPENSE			
4a	Other O&M Allocated to Transmission	Line 3 minus Line 3d	28,481,828	
4b	Annual Allocation Factor for Other O&M	Line 4a divided by Line 1, col 3	1.55%	1.55%
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Attach O, p 3, lines 10 & 11, col 5 (Note H)	2,694,659	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	0.15%	0.15%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach O, p 3, line 20 col 5	6,619,682	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1 col 3)	0.36%	0.36%
9	**Annual Allocation Factor for Other Expense**	**Sum of line 4b, 6, and 8**	**2.05%**	**2.05%**
	INCOME TAXES			
10	Total Income Taxes	Attach O, p 3, line 27 col 5	17,773,415	
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2 col 3)	1.4214%	1.42%
	RETURN			
12	Return on Rate Base	Attach O, p 3, line 28 col 5	84,043,469	
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2 col 3)	6.72%	6.72%
14	**Annual Allocation Factor for Return**	**Sum of line 11 and 13**		**8.14%**

Attachment MM
For the 12 months ended 12/31/2020

Formula Rate calculation

Rate Formula Template
Utilizing Attachment O Data

Northern Indiana Public Service Company LLC

Multi-Value Project (MVP) Revenue Requirement Calculation

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Line No.	**Project Name**	**MTEP Project Number**	**Project Gross Plant**	**Project Accumulated Depreciation**	**Transmission O&M Annual Allocation Factor**	**Annual Allocation for Transmission O&M Expense**	**Expense Annual Allocation Factor**	**Annual Allocation for Other Expense**	**Annual Expense Charge**	**Project Net Plant**	**Annual Allocation Factor for Return**	**Annual Return Charge**	**Project Depreciation Expense**	**Annual Revenue Requirement**	**True-Up Adjustment**	**MVP Annual Adjusted Revenue Requirement**
			(Note C)		Page 1 line 4	(Col 4 * Col 5)	Page 1 line 9	(Col 3 * Col 7)	(Col 6 + Col 8)	(Col 3 - Col 4)	(Page 1 line 14)	(Col 10 * Col 11)	(Note E)	Sum Col. 9, 12 & 13	(Note F)	Sum Col. 14 & 15 (Note G)
Multi-Value Projects (MVP)																
1a	MTEP11	2202	$ 171,822,029	$ 6,478,948	3.12%	$ 201,960	2.05%	$ 3,528,479	$ 3,730,439	$ 165,343,081	8.14%	$ 13,463,670	$ 3,700,185	$ 20,894,294	$ 132,152	$ 21,026,446
1b	MTEP11	3203	$ 396,042,644	$ 21,853,810	3.12%	$ 681,220	2.05%	$ 8,132,998	$ 8,814,218	$ 374,188,834	8.14%	$ 30,469,706	$ 11,420,679	$ 50,704,603	$ 3,533,002	$ 54,237,605
2	MVP Total Annual Revenue Requirements													$ 71,598,897	$ 3,665,154	$ 75,264,051
3	Rev. Req. Adj For Attachment O													$ 71,598,897		

Note Letter

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment O and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order less any prefunded AFUDC associated with gross plant and CWIP, if applicable. References to Attachment O "Column 5" throughout this template is an illustrative column designation intended to reference the appropriate right-most column in Attachment O which position may vary by company.

B Net Transmission Plant is that identified on page 2 line 14 of Attachment O and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes CWIP in rate base when authorized by FERC order less any prefunded AFUDC, if applicable. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

D Note deliberately left blank.

E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment O page 3 line 12, less any prefunded AFUDC amortization, if applicable, related to the project.

F True-Up Adjustment is included pursuant to a FERC approved methodology, if applicable.

G The MVP Annual Revenue Requirement is the value to be used in Schedules 26-A and 39.

H The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 13.

J Transmission Accumulated Depreciation that is identified on page 2 line 8 of Attachment O less any amortized prefunded AFUDC balance, if applicable.

K Project Accumulated Depreciation for the project is calculated in the same method as the Transmission Accumulated Depreciation value in line 1a.

Attachment MM - Supporting Data for Network Upgrade Charge Calculation - Forward Looking Rate Transmission Owner

Rate Year 2020

Reporting Company Northern Indiana Public Service Company LLC

	MTEP Project ID Pricing Zone Allocation Type Per Attachment FF	2202 - CWIP Central MVP	3203 - CWIP East MVP	2202 - In Service Central MVP	3203 - In Service East MVP
Gross Plant Column (3)	December 2019	$ -	$ -	$ 171,822,029	$ 396,042,644
	January 2020	-	-	171,822,029	396,042,644
	February	-	-	171,822,029	396,042,644
	March	-	-	171,822,029	396,042,644
	April	-	-	171,822,029	396,042,644
	May	-	-	171,822,029	396,042,644
	June	-	-	171,822,029	396,042,644
	July	-	-	171,822,029	396,042,644
	August	-	-	171,822,029	396,042,644
	September	-	-	171,822,029	396,042,644
	October	-	-	171,822,029	396,042,644
	November	-	-	171,822,029	396,042,644
	December 2020	-	-	171,822,029	396,042,644
	13 Month Average	$ -	$ -	$ 171,822,029	$ 396,042,644
Accumulated Depreciation Column (4)	December 2019	$ -	$ -	$ 4,628,856	$ 16,143,470
	January 2020	-	-	4,937,205	17,095,194
	February	-	-	5,245,553	18,046,917
	March	-	-	5,553,902	18,998,640
	April	-	-	5,862,251	19,950,363
	May	-	-	6,170,600	20,902,087
	June	-	-	6,478,948	21,853,810
	July	-	-	6,787,297	22,805,533
	August	-	-	7,095,646	23,757,257
	September	-	-	7,403,994	24,708,980
	October	-	-	7,712,343	25,660,703
	November	-	-	8,020,692	26,612,426
	December 2020	-	-	8,329,041	27,564,150
	13 Month Average	$ -	$ -	$ 6,478,948	$ 21,853,810
Net Plant Column (10)	December 2019	$ -	$ -	$ 167,193,173	$ 379,899,174
	January 2020	-	-	166,884,824	378,947,451
	February	-	-	166,576,476	377,995,728
	March	-	-	166,268,127	377,044,004
	April	-	-	165,959,778	376,092,281
	May	-	-	165,651,429	375,140,558
	June	-	-	165,343,081	374,188,835
	July	-	-	165,034,732	373,237,111
	August	-	-	164,726,383	372,285,388
	September	-	-	164,418,035	371,333,665
	October	-	-	164,109,686	370,381,941
	November	-	-	163,801,337	369,430,218
	December 2020	-	-	163,492,988	368,478,495
	13 Month Average	$ -	$ -	$ 165,343,081	$ 374,188,835
Depreciation Expense Column (13)	Project Depreciation Expense	$ -	$ -	$ 3,333,655	$ 10,984,391
	Project Amortization Expense	-	-	366,530	436,289
	Depreciation Expense Total	$ -	$ -	$ 3,700,185	$ 11,420,679

Attachment MM - Description of Facilities Included in Network Upgrade Charge

MTEP Project ID	Facility ID	Project Record Date	Description of Facilities Included in Network Upgrade Charge as of Record Date
3203	5949	MTEP11	Reynolds to Burr Oak to Hiple 345 kV line and tie in second AEP 345 kV circuits at Reynolds and Hiple
2202	4073	MTEP11	Reynolds to Greentown 765 kV line
2202	4074	MTEP11	Reynolds - New transformer