STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF A FUEL COST ADJUSTMENT TO BE APPLICABLE DURING THE BILLING MONTHS OF MAY, JUNE AND JULY 2012, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NO. 43969 AND FOR APPROVAL OF RATEMAKING TREATMENT FOR THE COST OF WIND POWER PURCHASES PURSUANT TO CAUSE NO. 43393.	))))))))))	**CAUSE NO. 38706-FAC94**

PETITIONER'S SUBMISSION OF AMENDED VERIFIED PETITION AND REVISED TESTIMONY AND EXHIBITS

Northern Indiana Public Service Company ("NIPSCO" or "Petitioner"), by counsel, hereby submits an Amended Verified Petition (Petitioner's Exhibit No. 1-A), Revised Page 3 and Revised Page 5 to the Verified Direct Testimony of Katherine A. Cherven filed in this Cause on February 2, 2012 (Petitioner's Exhibit No. 1) and Revised Exhibit 1-C and Revised Exhibit 1-D, both of which are included in the exhibits attached to Petitioner's Exhibit No. 1.

The foregoing have been revised to reflect a correction to the proposed factors. During the audit process, Petitioner discovered an error in the forecast for "Intersystem Sales through MISO" [Exhibit B, Schedule 1, Line 19] used to calculate the proposed factors for FAC 94. Although correcting this error does change the proposed FAC factors, it does not raise any new issues in this Cause as it was simply a clerical error.

A redlined copy and a clean copy of Revised Page 3, Revised Page 5, Revised Exhibit 1-C and Revised Exhibit 1-D is attached hereto. Petitioner will include the clean copy of the revised pages in its testimony and exhibits when it is offered into evidence at the hearing in this proceeding.

Respectfully submitted,

Erin Casper Borissov

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Northern Indiana Public Service Company

CERTIFICATE OF SERVICE

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

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Dated this 28th day of February, 2012.

Erin Casper Borissov

Erin Casper Borissov

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR APPROVAL OF A FUEL COST ADJUSTMENT TO BE APPLICABLE DURING THE BILLING MONTHS OF MAY, JUNE AND JULY 2012, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NO. 43969 AND FOR APPROVAL OF RATEMAKING TREATMENT FOR THE COST OF WIND POWER PURCHASES PURSUANT TO CAUSE NO. 43393.	)	CAUSE NO. 38706-FAC94

AMENDED VERIFIED PETITION

Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") petitions the Indiana Utility Regulatory Commission ("Commission") for approval of a fuel cost adjustment to be applicable during the billing months of May, June and July 2012, pursuant to Ind. Code § 8-1-2-42 and Cause No. 43969 and for approval of ratemaking treatment for the cost of wind power purchases pursuant to Cause No. 43393. In accordance with 170 IAC 1-1.1-8 and 1-1.1-9, Petitioner submits the following information in support of this petition.

Petitioner's Corporate and Regulated Status

1. NIPSCO is a public utility corporation 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 is engaged in rendering 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.

Relief Sought by Petitioner

2. In this proceeding, NIPSCO requests Commission approval of a fuel cost adjustment to be applicable and made effective for bills rendered by NIPSCO during the billing months of May, June and July 2012, pursuant to provisions of the Public Service Commission Act, as amended. NIPSCO also requests approval of ratemaking treatment for the cost of wind power purchases pursuant to the Commission's July 24, 2008 Order in Cause No. 43393. In addition, pursuant to the Commission's December 21, 2011 Order in NIPSCO's electric rate case (Cause No. 43969), NIPSCO seeks recovery of 25 percent of the credits paid to customers from December 27, 2011 through December 31, 2011, paid pursuant to NIPSCO's Rider 675 – Interruptible Industrial Service ("Recoverable Interruptible Credits").

3. Petitioner's proposed Appendix B – Fuel Cost Charge is attached

hereto as Petitioner's Exhibit A. Revised Sheet No. 202 reflects the fuel cost adjustment of (a) ($0.000840) per kilowatt hour for customers billed under Rate Schedules 611, 612, 613, 620, 621, 622, 623, 624, 625, 626, 632, 633, 634, 641, 642, 644, 650, 655 and 660, Rate Code 647 and Rider 676 and (b) $0.005429 per kilowatt hour for two existing customers billed under Rate Code 647 under contracts approved by the Commission that contain a different base fuel cost and require a special calculation until their expiration.

4. Petitioner's cost of fuel based upon the estimated average fuel cost for the three months of April, May and June 2012, the difference between the estimated incremental fuel cost billed and the incremental fuel cost actually experienced by Petitioner for the months of October, November and December 2011, and the Recoverable Interruptible Credit for the months of October, November and December 2011 is estimated to be $0.027902 [EXHIBIT B, SCHEDULE 1, PAGE 1, LINE 29] per kilowatt hour. The fuel cost adjustment modified for the recovery of Indiana Utility Receipts Tax on Retail Sales and Adjusted Gross Income Tax, will be (a) ($0.000840) per kilowatt hour for customers billed under Rate Schedules 611, 612, 613, 620, 621, 622, 623, 624, 625, 626, 632, 633, 634, 641, 642, 644, 650, 655 and 660, Rate Code 647 and Rider 676 [EXHIBIT B, SCHEDULE 1, PAGE 1, LINE 32] and (b) $0.005429 per kilowatt hour for two existing customers billed under Rate Code 647 under contracts approved by the Commission that contain a different base fuel cost

and require a special calculation until their expiration [EXHIBIT B, SCHEDULE 1, PAGE 2, LINE 4] , applied to bills rendered by Petitioner during the billing months of May, June and July 2012. The fuel cost adjustment, upon becoming effective, shall remain in effect for approximately three (3) months or until replaced by a different fuel cost adjustment that is approved in a subsequent filing. The estimated cost data supporting the fuel cost adjustment proposed herein is attached hereto as Petitioner's Exhibit B.

5. Petitioner's current fuel cost adjustment applicable to bills rendered by Petitioner during the billing months of February, March and April 2012 is a charge of (a) $0.004919 per kilowatt hour for customers billed under Rate Schedules 611, 612, 613, 620, 621, 622, 623, 624, 625, 626, 632, 633, 634, 641, 642, 644, 650, 655 and 660, Rate Code 647 and Rider 676 and (b) $0.011188 per kilowatt hour for two existing customers billed under Rate Code 647 under contracts approved by the Commission that contain a different base fuel cost and require a special calculation until their expiration.

6. Petitioner has made every reasonable effort to acquire fuel and generate and/or purchase power so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. The actual increases in fuel cost through December 2011, the latest month for which actual fuel costs are available since the

Commission's Order in Cause No. 43969 authorizing Petitioner to revise its basic rates and charges for electric service ("43969 Order"), have not been offset by actual decreases in other operating expenses. The fuel cost adjustment proposed herein will not result in Petitioner earning a return in excess of the return authorized by the 43969 Order and further adjusted for the Environmental Cost Recovery Mechanism return realized during the Reconciliation Period pursuant to the Commission Orders in Cause Nos. 42150 and subsequent tracker filings (42150-ECR-17).

7. Petitioner's estimate of prospective average fuel costs for the three calendar months of April, May and June 2012 are reasonable after taking into consideration: (i) the actual fuel costs experienced by Petitioner during the latest three calendar months for which actual fuel costs are available, and (ii) the estimated fuel costs for said latest three calendar months. Petitioner continues to monitor its estimation procedures, as described in its supporting testimony in this proceeding.

8. In the 43969 Order, the Commission did not order any changes to the Purchased Power Benchmark approved in Cause No. 43526, which found that each day, on a prospective basis, a "Benchmark" is established based upon a generic gas turbine ("GT"), using a generic GT heat rate of 12,500 btu/kwh using the Platt's Gas Daily Midpoint price for Chicago City Gate, plus a $0.17/mmbtu gas transport

charge for a generic gas-fired GT, which is then utilized to determine whether Petitioner incurred any Purchase Power Non Recoverable amounts ("Purchased Power Benchmark"). Petitioner's Exhibit No. 3-A shows the daily calculations of October, November and December 2011. Applying the Purchased Power Benchmark to Petitioner's purchased power transactions included in this proceeding, Petitioner is not requesting recovery of any non-recoverable purchased power costs in excess of the Purchased Power Benchmark for the months of October, November and December 2011.

9. In its June 30, 2009 Order in Cause No. 43665, the Commission found that each day, on a prospective basis, a "Benchmark" is established based upon a generic GT, using a generic GT heat rate of 12,500 btu/kwh, using the Henry Hub Gas prompt month price plus $0.60/mmbtu gas transport charge for a generic gas-fired GT, which is then utilized to determine whether Petitioner incurred any Contestable Real-Time Revenue Sufficiency Guarantee ("RSG") amounts ("RSG Benchmark"). Petitioner's Exhibit No. 3-B shows the daily calculations of October, November and December 2011. Applying the RSG Benchmark to Petitioner's RSG charges included in this proceeding, Petitioner is not requesting recovery of any Contestable Real-Time RSG amounts for the months of October, November and December 2011.

10. Consistent with prior FAC proceedings, Petitioner continues to seek Commission approval of Petitioner's ratemaking treatment of wind power purchase costs pursuant to the Commission's July 24, 2008 Order in Cause No. 43393.

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. NIPSCO respectfully requests that a Commission order be issued in this matter by April 30, 2012, which is the beginning of the consumption period reflected in NIPSCO's May 2012 billing cycle.

Applicable Law

13. Petitioner considers the provisions of the Public Service Commission Act, as amended, including Ind. Code §§ 8-1-1-8 and 8-1-2-42, 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

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

Counsel of Record:

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With a copy to:

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WHEREFORE, Northern Indiana Public Service Company respectfully requests that the Commission promptly publish notice, make such other investigation and hold such hearings as are necessary or advisable on or before April 11, 2012 in this Cause and thereafter, make and enter an order in this Cause:

(a) Authorizing and approving the fuel cost adjustment set forth in Paragraph 4 to become effective for bills rendered by NIPSCO during the billing months of May, June and July 2012;

(b) Approving Petitioner's Appendix B – Fuel Cost Charge, First Revised Sheet No. 202 of its IURC Electric Service Tariff, Original Volume No. 12 set forth in Petitioner's Exhibit A to this Petition, which contains the fuel cost adjustment to become effective for bills rendered by NIPSCO during the billing months of May, June and July 2012;

(c) Issuing such order within twenty (20) days from the date the Commission receives the report of the Indiana Office of Utility Consumer

Counselor; and

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

Dated this 28th day of February, 2012.

Northern Indiana Public Service Company

Linda E. Miller
Executive Director, Rates & Regulatory Finance

Verification

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

Dated: February 28, 2012.

Linda E. Miller
Executive Director, Rates & Regulatory Finance

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Attorney for Petitioner
Northern Indiana Public Service Company

APPENDIX B
FUEL COST CHARGE

The charges in Rates Schedules 611, 612, 613, 620, 621, 622, 623, 624, 625, 626, 632, 633, 634, 641, 642, 644, 650, 655 and 660, Rate Code 647 and Rider 676 are subject to the Fuel Cost Charge computed in accordance with Rider 670 – Adjustment of Charges for Cost of Fuel Rider.

Effective for all bills rendered during the May, June and July 2012 billing months, the Fuel Cost Charge shall be:

A credit of $0.000840 per kilowatt hour

The Fuel Cost Charge for Rate Code 647 is applicable to all customers billed under this rate code under contracts approved by the Commission.

Effeetive for all bills rendered under Rate Code 647 during the May, June and July 2012 billing months, the Fuel Cost Charge shall be:

A charge of $0.005429 per kilowatt hour

CAUSE NO. 38706-FAC94
EXHIBIT B
REVISED SCHEDULE 1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Determination of Fuel Cost Charge Factor
For the Billing Months of

May 2012, June, 2012 and July, 2012

LINE NO.	DESCRIPTION	Based on the Estimated Average of: April 2012	May 2012	June, 2012	TOTAL	ESTIMATED THREE MONTH AVERAGE FOR THE BILLING MONTHS OF May 2012, June, 2012 and July, 2012	LINE NO.
	SOURCE - MWH						
1	Steam Generation	1,104,409	1,369,283	1,414,995	3,888,687	1,296,229	1
2	Nuclear Generation	-	-	-	-	-	2
3	Hydro Generation	6,197	5,996	5,156	17,349	5,783	3
4	Other Generation	514	372	2,660	3,566	1,189	4
5	Purchases through MISO	318,954	142,114	156,678	619,746	206,582	5
6	Wind Energy Purchases	22,527	25,999	17,525	66,051	22,017	6
	Less:						
7	Energy Losses and Company Use	72,498	74,821	80,415	227,734	75,911	7
8	Intersystem Sales through MISO	84,709	132,076	81,743	298,526	99,509	8
9	Intersystem Sales other than MISO	-	-	-	-	-	9
10	Jurisdictional Sales not Subject to FAC	-	-	-	-	-	10
11	TOTAL SALES (S)	1,295,394	1,336,867	1,430,876	4,069,137	1,356,380	11
	FUEL COST						
12	Steam Generation [a]	$ 30,553,824	$ 38,537,658	$ 40,035,745	$ 109,127,227	$ 36,375,742	12
13	Nuclear Generation	-	-	-	-	-	13
14	Hydro Generation	-	-	-	-	-	14
15	Other Generation [a]	26,239	19,189	145,522	190,950	63,650	15
16	Purchases through MISO	7,279,590	3,033,276	3,321,474	13,634,340	4,544,780	16
17	MISO Components of Cost of Fuel	1,317,236	1,317,236	1,317,236	3,951,708	1,317,236	17
18	Purchased Power other than MISO	1,105,819	1,278,425	860,981	3,245,225	1,081,742	18
	Less:						
19	Intersystem Sales through MISO	2,461,756	3,936,061	2,463,339	8,861,156	2,960,385	19
20	Intersystem Sales other than MISO	-	-	-	-	-	20
21	Jurisdictional Sales not Subject to FAC	-	-	-	-	-	21
22	Wind PPA Adjustment	72,546	72,546	72,546	217,638	72,546	22
23	Purchase Power Benchmark Adjustment	-	-	-	-	-	23
24	TOTAL FUEL COST (F)	$ 37,728,406	$ 40,177,177	$ 43,145,073	$ 121,050,656	$ 40,350,219	24
25	FUEL COST (mills/kwh)					29.748	25
	MONTHS TO BE RECONCILED:	October, 2011	November, 2011	December, 2011	TOTAL		
26	FUEL COST VARIANCE - UNDER/(OVER) COLLECTION	$ (1,340,765)	$ (3,263,122)	$ (3,015,979)	$ (7,619,866)		26
26a	CREDIT FROM EARNINGS TEST (Total from Exhibit 2-B, line 13e)				$ -		26a
26b	ADJUST TAXES IMBEDDED IN CREDIT ON LINE				$ -		26b
26c					$ -		26c
26d	SUBTOTAL LINES 26, 26a, 26b AND 26c				$ (7,619,866)		26d
27	VARIANCE FACTOR - LINE 25d DIVIDED BY ESTIMATED INDIANA JURISDICTIONAL SALES OF 4,069,137 MWH (mills/kwh)					(1.873)	27
28	RECOVERABLE INTERRUPTIBLE CREDIT FACTOR(mills/kwh) (Sch 8)					0.027	28
29	ADJUSTED FUEL COST FACTOR (mills/kwh) (Line 25 + Line 27 + Line 28)					27.902	29
30	LESS BASE COST OF FUEL IN RATES (mills/kwh)					28.729	30
31	FUEL COST CHARGE FACTOR (mills/kwh) (Line 29 - Line 30)					(0.827)	31
32	FUEL COST CHARGE FACTOR ADJUSTED FOR URTRS and AGIT (mills/kwh) [b]					(0.840)	32

Notes:
[a] Contains Account No. 151 charges only
[b] Adjustment for Utility Receipts Tax on Retail Sales (URTRS) of 1.4% grossed up for Adjusted Gross Income Tax.

CAUSE NO. 38706-FAC94
EXHIBIT B
REVISED SCHEDULE 1

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Determination of FAC Rate for Special Contracts
For the Estimated Months of
April 2012, May 2012 and June, 2012
And the Billing Months of
May 2012, June, 2012 and July, 2012

LINE NO.				LINE NO.
1	ADJUSTED FUEL COST FACTOR (mills/kwh) (Sch1, Line 29)	$	27.902	1
2	LESS BASE COST OF FUEL IN SPECIAL CONTRACT RATE CODE 647 (mills/kwh)	$	22.556	2
3	FUEL COST CHARGE FACTOR FOR SPECIAL CONTRACT RATE CODE 647 (mills/kwh)	$	5.346	3
4	FUEL COST CHARGE FACTOR FOR SPECIAL CONTRACT RATE CODE 647 ADJUSTED FOR URTRS AND AGIT	$	5.429	4

CAUSE NO. 38706-FAC94
EXHIBIT B
SCHEDULE 2

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Determination of Net Energy Cost of Purchased Power
For the Estimated Months of

April 2012, May 2012 and June, 2012

And the Billing Months of

May 2012, June, 2012 and July, 2012

LINE NO.	SUPPLIER	MWH PURCHASED	ENERGY *	LINE NO.
	April 2012			
1	Purchases through MISO	318,954	$ 7,279,590	1
2	MISO Components of Cost of Fuel	-	1,317,236	2
3	Wind Energy Purchases	22,527	1,105,819	3
4	TOTAL	341,481	$ 9,702,645	4
	May 2012			
5	Purchases through MISO	142,114	$ 3,033,276	5
6	MISO Components of Cost of Fuel	-	1,317,236	6
7	Wind Energy Purchases	25,999	1,278,425	7
8	TOTAL	168,113	$ 5,628,937	8
	June, 2012			
9	Purchases through MISO	158,678	$ 3,321,474	9
10	MISO Components of Cost of Fuel	-	1,317,236	10
11	Wind Energy Purchases	17,525	860,981	11
12	TOTAL	176,203	$ 5,499,691	12
13	Total Net Energy Cost of Other Purchased Power	685,797	$ 20,831,273	13

* Demand Charges have not been estimated.

CAUSE NO. 38706-FAC94
EXHIBIT B
REVISED SCHEDULE 3

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Determination of Fuel Costs Recovered Through
Intersystem and Jurisdictional Sales not Subject to FAC by Month
For the Estimated Months of

April 2012, May 2012 and June, 2012

And the Billing Months of

May 2012, June, 2012 and July, 2012

LINE NO.	PURCHASER	MWH SOLD		FUEL COST *	LINE NO.
	April 2012				
1	Intersystem Sales through MISO	84,709	$	2,481,756	1
2	Intersystem Sales other than MISO	-		-	2
3	Jurisdictional Sales not Subject to FAC	-		-	3
4	Wind PPA Adjustment	-		72,546	4
5	Purchase Power Benchmark Adjustment	-		-	5
6	TOTAL	84,709	$	2,554,302	6
	May 2012				
7	Intersystem Sales through MISO	132,076	$	3,936,061	7
8	Intersystem Sales other than MISO	-		-	8
9	Jurisdictional Sales not Subject to FAC	-		-	9
10	Wind PPA Adjustment			72,546	10
11	Purchase Power Benchmark Adjustment	-		-	11
12	TOTAL	132,076	$	4,008,607	12
	June, 2012				
13	Intersystem Sales through MISO	81,743	$	2,463,339	13
14	Intersystem Sales other than MISO	-		-	14
15	Jurisdictional Sales not Subject to FAC	-		-	15
16	Wind PPA Adjustment			72,546	16
17	Purchase Power Benchmark Adjustment	-		-	17
18	TOTAL	81,743	$	2,535,885	18
19	Total Net Energy Cost of Purchased Power	298,528	$	9,098,794	19

* Demand Charges have not been estimated.

CAUSE NO.38706-FAC94
EXHIBIT B
SCHEDULE 4
PAGE 1 OF 3

NORTHERN INDIANA PUBLIC SERVICE COMPANY
RECONCILIATION OF ACTUAL INCREMENTAL COST OF FUEL INCURRED TO APPLICABLE INCREMENTAL RETAIL FUEL CLAUSE
For the Month of OCTOBER 2011

LINE NO.	CLASS OF CUSTOMER	KWH SALES (000'S) (1)	BASE COST OF FUEL IN RATES (MILLS/KWH) 22.556 (2)	ACTUAL COST OF FUEL INCURRED 30.278 (3)	ACTUAL INCREMENTAL COST OF FUEL (COL 3-2) (4)	ACTUAL INCREMENTAL COST OF FUEL BILLED INCLUDING URTRS 7.031 (5)	ACTUAL INCREMENTAL COST OF FUEL BILLED EXCLUDING URTRS 6.923 (6)	ACTUAL INCREMENTAL COST CREDIT FACTOR FOR SETTLEMENT FAC71S 0.000 (6)	FUEL COST VARIANCE FROM CAUSE NO. 38706-FAC91 ($2,355,579) (7)	CREDIT FROM EARNINGS TEST $0 (7a)	CREDIT FROM 38706-FAC91 ($2,391) (7b)	FUEL CLAUSE REVENUES TO BE RECONCILED WITH INCREMENTAL COST OF FUEL INCURRED (8)	FUEL COST VARIANCE (COL 4-8) (9)	LINE NO.
1	RESIDENTIAL	222,687	$ 5,022,928	$ 6,742,517	$ 1,719,589	$ 1,565,712	$ 1,541,662	$ -	$ (411,501)	$ -	$ (418)	$ 1,953,581	$ (233,992)	1
2	COMMERCIAL	308,844	6,966,285	9,351,179	2,384,894	2,171,482	2,138,127	-	(570,710)	-	(579)	2,709,416	(324,522)	2
3	INDUSTRIAL	740,491	16,702,515	22,420,586	5,718,071	5,206,392	5,126,419	-	(1,368,347)	-	(1,389)	6,496,155	(778,084)	3
4	OTHER	2,717	61,285	82,265	20,980	19,103	18,810	-	(5,021)	-	(5)	23,836	(2,856)	4
5	TOTAL RETAIL SALES SUBJECT TO FCA	1,274,739	$ 28,753,013	$ 38,596,547	$ 9,843,534	$ 8,962,689	$ 8,825,018	$ -	$ (2,355,579)	$ -	$ (2,391)	$ 11,182,966	$ (1,339,484)	5
5a	Less: Purchased Power Adjustment												$ -	5a
5b	Contestable RSG Adjustment												$ 1,311	5b
													$ (1,340,765)	
6	TOTAL RETAIL SALES NOT SUBJECT TO FCA:													6
7	STR LTG & SPECIAL CONTRACTS	12,116		$ 367,469										7
8	CUSTOMER BUY THROUGH	-		$ -										8
9	BACK UP AND MAINTENANCE	29,699		1,026,417										9
10	SUBTOTAL	1,316,556		$ 39,990,433										10
11	UNBILLED SALES	25,317												11
12	SUBTOTAL BOOKED COMPANY LOAD	1,341,872												12
13	PURCHASED POWER ADJUSTMENT			-										13
14	WIND PPA ADJUSTMENT			41,041										14
15	SALES FOR RESALE	-		-										15
16	INTERSYSTEM SALES	29,473		739,537										16
17	TOTAL NON-JURISDICTIONAL SALE	29,473		$ 780,578										17
18	TOTAL BOOKED SALES	1,371,345		$ 40,771,011										18

NORTHERN INDIANA PUBLIC SERVICE COMPANY
RECONCILIATION OF ACTUAL INCREMENTAL COST OF FUEL
INCURRED TO APPLICABLE INCREMENTAL RETAIL FUEL CLAUSE
FOR THE MONTH OF
NOVEMBER 2011

LINE NO.	CLASS OF CUSTOMER	KWH SALES (000'S)	BASE COST OF FUEL IN RATES (MILLS/KWH) 22.556	ACTUAL COST OF FUEL INCURRED 28.628	ACTUAL INCREMENTAL COST OF FUEL (COL 3-2)	ACTUAL INCREMENTAL COST OF FUEL BILLED INCLUDING URTRS 9.344	ACTUAL INCREMENTAL COST OF FUEL BILLED EXCLUDING URTRS 9.201	ACTUAL INCREMENTAL COST CREDIT FACTOR FOR SETTLEMENT FAC71S 0.000	FUEL COST VARIANCE FROM CAUSE NO. 38706-FAC92 $567,793	CREDIT FROM EARNINGS TEST $0	CREDIT FROM 38706-FAC92 $0	FUEL CLAUSE REVENUES TO BE RECONCILED WITH INCREMENTAL COST OF FUEL INCURRED	FUEL COST VARIANCE (COL 4-8)	LINE NO.
		(1)	(2)	(3)	(4)	(5)	(6)	(6)	(7)	(7a)	(7b)	(8)	(9)	
1	RESIDENTIAL	232,411	$ 5,242,263	$ 6,653,462	$ 1,411,199	$ 2,171,648	$ 2,138.414	$ -	$ 107,841	$ -	$ -	$ 2,030,573	$ (619,374)	1
2	COMMERCIAL	298,602	6,735,267	8,548,378	1,813,111	2,790,137	2,747,437	-	138,555	-	-	2,608,882	(795,771)	2
3	INDUSTRIAL	689,867	15,560,640	19,749,512	4,188,872	6,446,117	6,347,466	-	320,106	-	-	6,027,360	(1,838,488)	3
4	OTHER	2,781	62,728	79,614	16,886	25,986	25,588	-	1,290	-	-	24,298	(7,412)	4
5	TOTAL RETAIL SALES SUBJECT TO FCA	1,223,661	$ 27,600,898	$ 35,030,966	$ 7,430,068	$ 11.433.888	$ 11,258.905	$ -	$ 567,792	3 -	$ -	$ 10,691,113	$ (3,261,045)	5
5a	Less: Purchased Power Adjustment												$ -	5a
5b	Contestable RSG Adjustment												$ 2,077	5b
													$ (3,263,122)	
6	TOTAL RETAIL SALES NOT SUBJECT TO FCA:													6
7	STR LTG & SPECIAL CONTRACTS	11,336		$ 324,663										7
8	CUSTOMER BUY THROUGH	-		$ -										8
9	BACK UP AND MAINTENANCE	27,850		901,750										9
10	SUBTOTAL	1,262,847		$ 36.257,379										10
11	UNBILLED SALES	20,350												11
12	SUBTOTAL BOOKED COMPANY LOAD	1,283,197												12
13	PURCHASED POWER ADJUSTMENT			-										13
14	WIND PPA ADJUSTMENT			62,350										14
15	SALES FOR RESALE	-		-										15
16	INTERSYSTEM SALES	38,218		918,473										16
17	TOTAL NON-JURISDICTIONAL SALE	38.216		$ 980,823										17
18	TOTAL BOOKED SALES	1,321,415		$ 37,236,203										18

NORTHERN INDIANA PUBLIC SERVICE COMPANY
RECONCILIATION OF ACTUAL INCREMENTAL COST OF FUEL
INCURRED TO APPLICABLE INCREMENTAL RETAIL FUEL CLAUSE
FOR THE MONTH OF
DECEMBER 2011

600 Rates

LINE NO.	CLASS OF CUSTOMER	KWH SALES (000'S) (1)	BASE COST OF FUEL IN RATES (MILLS/KWH) 28.729 (2)	ACTUAL COST OF FUEL INCURRED 29.004 (3)	ACTUAL INCREMENTAL COST OF FUEL (COL 3-2) (4)	ACTUAL INCREMENTAL COST OF FUEL BILLED INCLUDING URTRS 3.075 (5)	ACTUAL INCREMENTAL COST OF FUEL BILLED EXCLUDING URTRS 3.028 (6)
1	RESIDENTIAL	4,161.27	$ 119,549	$ 120,694	$ 1,144	$ 12,796	$ 12,600
2	COMMERCIAL	5,652.35	$ 162,386	$ 163,841	$ 1,554	$ 17,381	$ 17,115
3	INDUSTRIAL	82,524.38	$ 2,370,843	$ 2,393,537	$ 22,694	$ 253,762	$ 249,884
4	LIGHTING	1,254.40	$ 36,038	$ 36,383	$ 345	$ 3,857	$ 3,798
5	PUBLIC AUTHORITY	13.66	$ 392	$ 396	$ 4	$ 42	$ 41
6	RAILROAD	229.25	$ 6,586	$ 6,649	$ 63	$ 705	$ 694
5	TOTAL RETAIL SALES SUBJECT TO FAC:	93,835	$ 2,695,785	$ 2,721,599	$ 25,805	$ 288,544	$ 284,133

600 Rates

LINE NO.	CLASS OF CUSTOMER	KWH SALES (000'S) (1)	BASE COST OF FUEL IN RATES (MILLS/KWH) 22.556 (2)	ACTUAL COST OF FUEL INCURRED 29.004 (3)	ACTUAL INCREMENTAL COST OF FUEL (COL 3-2) (4)	INCREMENTAL COST OF FUEL BILLED INCLUDING URTRS 9.344 (5)	INCREMENTAL COST OF FUEL BILLED EXCLUDING URTRS 9.201 (6)
1	RESIDENTIAL	271,665.69	$ 6,127,691	$ 7,879,391	$ 1,751,700	$ 2,538,444	$ 2,499,596
2	COMMERCIAL	303,815.15	$ 6,852,855	$ 8,811,855	$ 1,959,000	$ 2,838,849	$ 2,795,403
3	INDUSTRIAL	629,126	$ 14,190,568	$ 18,247,173	$ 4,056,605	$ 5,878,554	$ 5,788,589
4	PUBLIC AUTHORITY	1,553	$ 35,034	$ 45,049	$ 10,015	$ 14,513	$ 14,291
5	RAILROAD	1,628	$ 36,710	$ 47,204	$ 10,494	$ 15,207	$ 14,975
6	TOTAL RETAIL SALES SUBJECT TO FAC:	1,207,788	$ 27,242,857	$ 35,030,671	$ 7,787,814	$ 11,285,567	$ 11,112,884

TOTAL

LINE NO.	CLASS OF CUSTOMER	KWH SALES (000'S) (1)	BASE COST OF FUEL IN RATES (MILLS/KWH) (2)	ACTUAL COST OF FUEL INCURRED 29.004 (3)	ACTUAL INCREMENTAL COST OF FUEL (COL 3-2) (4)	INCREMENTAL COST OF FUEL BILLED INCLUDING URTRS (5)	INCREMENTAL COST OF FUEL BILLED EXCLUDING URTRS (6)	VARIANCE FROM CAUSE NO. 38706-FAC92 567,793 (7)	CREDIT FROM 38706-FAC92 0 (7b)	REVENUES TO BE RECONCILED WITH INCREMENTAL COST OF FUEL INCURRED (8)	FUEL COST VARIANCE (COL 4-6) (9)	LINE NO.
1	RESIDENTIAL	279,827	$ 6,247,240	$ 8,000,084	$ 1,752,844	$ 2,551,240	$ 2,512,196	$ 120,321	$ -	$ 2,391,875	$ (639,031)	1
2	COMMERCIAL	309,468	$ 7,015,241	$ 8,975,796	$ 1,960,554	$ 2,856,230	$ 2,812,519	$ 134,996	$ -	$ 2,677,523	$ (716,968)	2
3	INDUSTRIAL	711,650	$ 16,561,411	$ 20,640,710	$ 4,079,299	$ 6,132,317	$ 6,038,473	$ 310,436	$ -	$ 5,728,037	$ (1,648,738)	3
4	LIGHTING	1,254	$ 36,038	$ 36,383	$ 345	$ 18,371	$ 18,089	$ 547	$ -	$ 17,542	$ (17,197)	4
5	PUBLIC AUTHORITY	1,567	$ 35,427	$ 45,445	$ 10,019	$ 15,249	$ 15,016	$ 683	$ -	$ 14,332	$ (4,314)	5
6	RAILROAD	1,857	$ 43,296	$ 53,853	$ 10,557	$ 705	$ 694	$ 810	$ -	$ (116)	$ 10,673	6
7	TOTAL RETAIL SALES SUBJECT TO FAC:	1,301,623	$ 29,938,552	$ 37,752,271	$ 7,813,819	$ 11,574,111	$ 11,396,987	$ 567,793	$ -	$ 10,829,194	$ (3,015,575)	7
	Less: Purchased Power Adjustment										$ -	
	Contestable RSG Adjustment										$ 404	
	TOTAL RETAIL SALES										$ (3,015,979)	

TOTAL RETAIL SALES NOT SUBJECT TO FAC:

LINE NO.		KWH SALES (000'S)	ACTUAL COST OF FUEL INCURRED
8	BACK UP AND MAINTENANCE	16,613	$ 539,557
9	COMPANY USE	5,064	$ -
10	CUSTOMER BUY THROUGH	-	$ -
11	RATE 845	30,305	$ 900,159
12	STREET LIGHTING (800 SERIES)	5,270	$ 329,339
13	SUBTOTAL	1,359,899	$ 39,521,335
14	UNBILLED SALES	3,636	
15	SUBTOTAL BOOKED COMPANY LOAD	1,363,534	
16	PURCHASED POWER ADJUSTMENT		$ -
17	WIND PPA ADJUSTMENT		$ 77,342
18	SALES FOR RESALE	-	$ -
19	INTERSYSTEM SALES	76,439	$ 1,921,335
20	TOTAL NON-JURISDICTIONAL SALES	76,439	$ 1,998,676
21	TOTAL BOOKED SALES	1,439,973	$ 41,520,011

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COMPARISON OF ACTUAL AND ESTIMATED COST OF FUEL
FOR THE MONTH OF

OCTOBER 2011

LINE NO.	DESCRIPTION	ACTUAL OCTOBER 2011	FORECAST OCTOBER 2011	LINE NO.
	KWH SOURCE (000'S)			
1	Steam Generation	1,214,753	1,116,808	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	3,322	2,679	3
4	Other Generation	480	372	4
5	Purchases through MISO	144,209	229,085	5
6	Purchased Power other than MISO	70,692	26,235	6
7	Power Received for Other Systems	112,537	-	7
	LESS:			
8	Jurisdictional Sales not Subject to FAC	41,817	27,800	8
9	Intersystem Sales through MISO	29,464	4,040	9
10	Intersystem Sales other than MISO	9	-	10
11	Power Transmitted for Other Systems	112,537	-	11
12	Energy Losses and Company Use	87,428	75,412	12
13	SALES (S)	1,274,738	1,267,927	13
	FUEL COST (F)			
14	Steam Generation	$ 33,922,426	$ 31,799,930	14
15	Nuclear Generation	-	-	15
16	Hydro Generation	-	-	16
17	Other Generation	35,371	30,032	17
18	Purchases through MISO	4,775,099	7,086,552	18
19	MISO Components of Cost of Fuel	546,351	819,450	19
20	Purchased Power other than MISO	1,491,764	1,270,533	20
	LESS:			
21	Jurisdictional Sales not Subject to FAC	1,393,886	830,587	21
22	Intersystem Sales through MISO	582,066	117,344	22
23	Intersystem Sales other than MISO	(8,223)	-	23
24	Transmission Losses	165,694	-	24
25	Purchases over the Benchmark	-	-	25
26	Wind PPA Adjustment	41,041	-	26
27	TOTAL FUEL COSTS (F)	$ 38,596,547	$ 40,058,566	27
28	FUEL COST PER KWH (IN MILLS) F/S	$ **30.278**	$ **31.594**	28
29	Weighted Average Deviation	4.35%		29

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COMPARISON OF ACTUAL AND ESTIMATED COST OF FUEL
FOR THE MONTH OF

NOVEMBER 2011

LINE NO.	DESCRIPTION	ACTUAL NOVEMBER 2011	FORECAST NOVEMBER 2011	LINE NO.
	KWH SOURCE (000'S)			
1	Steam Generation	1,202,364	1,204,549	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	4,526	3,234	3
4	Other Generation	2,010	360	4
5	Purchases through MISO	95,688	122,192	5
6	Purchased Power other than MISO	85,296	31,660	6
7	Power Received for Other Systems	155,400	-	7
	LESS:			
8	Jurisdictional Sales not Subject to FAC	39,186	29,000	8
9	Intersystem Sales through MISO	38,212	6,349	9
10	Intersystem Sales other than MISO	6	-	10
11	Power Transmitted for Other Systems	155,400	-	11
12	Energy Losses and Company Use	88,819	74,561	12
13	SALES (S)	1,223,661	1,252,085	13
	FUEL COST (F)			
14	Steam Generation	$ 31,934,809	$ 34,204,663	14
15	Nuclear Generation	-	-	15
16	Hydro Generation	-	-	16
17	Other Generation	116,432	30,195	17
18	Purchases through MISO	2,404,207	3,702,698	18
19	MISO Components of Cost of Fuel	825,715	819,450	19
20	Purchased Power other than MISO	1,957,039	1,529,701	20
	LESS:			
21	Jurisdictional Sales not Subject to FAC	1,226,413	859,838	21
22	Intersystem Sales through MISO	646,543	184,677	22
23	Intersystem Sales other than MISO	(18,740)	-	23
24	Transmission Losses	290,670	-	24
25	Purchases over the Benchmark	-	-	25
26	Wind PPA Adjustment	62,350	-	26
27	TOTAL FUEL COSTS (F)	$ 35,030,966	$ 39,242,192	27
28	FUEL COST PER KWH (IN MILLS) F/S	$ 28.628	$ 31.341	28
29	Weighted Average Deviation	9.48%		29

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COMPARISON OF ACTUAL AND ESTIMATED COST OF FUEL
FOR THE MONTH OF

DECEMBER 2011

LINE NO.	DESCRIPTION	ACTUAL DECEMBER 2011	FORECAST DECEMBER 2011	LINE NO.
	KWH SOURCE (000'S)			
1	Steam Generation	1,309,502	1,376,191	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	9,323	5,946	3
4	Other Generation	309	372	4
5	Purchases through MISO	129,689	106,135	5
6	Purchased Power other than MISO	78,919	24,106	6
7	Power Received for Other Systems	150,633	-	7
	LESS:			
8	Jurisdictional Sales not Subject to FAC	58,276	27,800	8
9	Intersystem Sales through MISO	76,432	71,713	9
10	Intersystem Sales other than MISO	7	-	10
11	Power Transmitted for Other Systems	150,633	-	11
12	Energy Losses and Company Use	91,404	79,258	12
13	SALES (S)	1,301,623	1,333,979	13
	FUEL COST (F)			
14	Steam Generation	$ 34,889,922	$ 39,788,779	14
15	Nuclear Generation	-	-	15
16	Hydro Generation	-	-	16
17	Other Generation	21,278	32,409	17
18	Purchases through MISO	3,145,030	2,922,622	18
19	MISO Components of Cost of Fuel	1,644,811	819,450	19
20	Purchased Power other than MISO	1,818,971	1,166,332	20
	LESS:			
21	Jurisdictional Sales not Subject to FAC	1,769,064	825,245	21
22	Intersystem Sales through MISO	1,446,418	2,517,418	22
23	Intersystem Sales other than MISO	88,962	-	23
24	Transmission Losses	385,955	-	24
25	Purchases over the Benchmark	-	-	25
26	Wind PPA Adjustment	77,342	-	26
27	TOTAL FUEL COSTS (F)	$ 37,752,271	$ 41,386,929	27
28	FUEL COST PER KWH (IN MILLS) F/S	$ 29.004	$ 31.025	28
29	Weighted Average Deviation	6.97%		29

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COMPARISON OF ACTUAL AND ESTIMATED COST OF FUEL
FOR THE MONTHS OF
OCTOBER, NOVEMBER, AND DECEMBER 2011

LINE NO.	DESCRIPTION	ACTUAL	FORECAST	LINE NO.
	KWH SOURCE (000'S)			
1	Steam Generation	3,726,619	3,697,548	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	17,171	11,859	3
4	Other Generation	2,799	1,104	4
5	Purchases through MISO	369,686	457,412	5
6	Purchased Power other than MISO	234,907	82,001	6
7	Power Received for Other Systems	418,570	-	7
			-	
	LESS:		-	
			-	
8	Jurisdictional Sales not Subject to FAC	139,279	84,600	8
9	Intersystem Sales through MISO	144,108	82,102	9
10	Intersystem Sales other than MISO	22	-	10
11	Power Transmitted for Other Systems	418,570	-	11
12	Energy Losses and Company Use	267,651	229,231	12
13	SALES (S)	3,800,022	3,853,991	13
	FUEL COST (F)			
14	Steam Generation	$ 100,747,157	$ 105,793,372	14
15	Nuclear Generation	-	-	15
16	Hydro Generation	-	-	16
17	Other Generation	173,081	92,636	17
18	Purchases through MISO	10,324,336	13,711,872	18
19	MISO Components of Cost of Fuel	3,016,877	2,458,350	19
20	Purchased Power other than MISO	5,267,774	3,966,566	20
			-	
	LESS:		-	
			-	
21	Jurisdictional Sales not Subject to FAC	4,389,363	2,515,670	21
22	Intersystem Sales through MISO	2,675,027	2,819,439	22
23	Intersystem Sales other than MISO	61,999	-	23
24	Transmission Losses	842,319	-	24
25	Purchases over the Benchmark	-	-	25
26	Wind PPA Adjustment	180,733	-	26
27	TOTAL FUEL COSTS (F)	$ 111,379,784	$ 120,687,687	27
28	FUEL COST PER KWH (IN MILLS) F/S	**$ 29.310**	**$ 31.315**	28
29	Weighted Average Deviation	6.84%		29

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF FUEL RECONCILIATION
Summary of Generation
OCTOBER 2011

Line No.				Line No.
	NIPSCO Generation	MWH	Amount	
1	Steam Generation	1,214,753	$ 33,922,426	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	3,322	-	3
4	Other Generation	480	35,371	4
5	**Total Generation**	**1,218,555**	**$ 33,957,797**	5

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF FUEL RECONCILIATION
Summary of Generation
NOVEMBER 2011

Line No.	NIPSCO Generation	MWH	Amount	Line No.
1	Steam Generation	1,202,364	$ 31,934,809	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	4,526	-	3
4	Other Generation	2,010	116,432	4
5	**Total Generation**	**1,208,900**	**$ 32,051,241**	5

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF FUEL RECONCILIATION
Summary of Generation
DECEMBER 2011

Line No.		MWH	Amount	Line No.
	NIPSCO Generation			
1	Steam Generation	1,309,502	$ 34,889,922	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	9,323	-	3
4	Other Generation	309	21,278	4
5	**Total Generation**	**1,319,134**	**$ 34,911,200**	5

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF FUEL RECONCILIATION
Summary of Purchased Power Subject to the Benchmark
OCTOBER 2011

Line No.				Line No.
	Purchased Power Subject to the Benchmark	MWH	Amount	
1	Purchases through MISO	144,209	$ 4,775,099	1
2	Purchased Power other than MISO	(18,715)	$ (694,030)	2
3	NIPSCO Transmission Losses	-	$ -	3
4	**Total Purchased Power Subject to the Benchmark**	**125,494**	**$ 4,081,069**	4
5	Non-Recoverable Purchased Power Costs		$ -	5
6	Recoverable Purchased Power Costs		$ 4,081,069	6

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF FUEL RECONCILIATION
Summary of Purchased Power Subject to the Benchmark
NOVEMBER 2011

Line No.	Purchased Power Subject to the Benchmark	MWH	Amount	Line No.
1	Purchases through MISO	95,688	$ 2,404,207	1
2	Purchased Power other than MISO	(6,421)	$ (238,740)	2
3	NIPSCO Transmission Losses	-	$ -	3
4	**Total Purchased Power Subject to the Benchmark**	**89,267**	**$ 2,165,467**	4
5	Non-Recoverable Purchased Power Costs		$ -	5
6	Recoverable Purchased Power Costs		$ 2,165,467	6

NORTHERN INDIANA PUBLIC SERVICE COMPANY
COST OF FUEL RECONCILIATION
Summary of Purchased Power Subject to the Benchmark
DECEMBER 2011

Line No.	**Purchased Power Subject to the Benchmark**	MWH	Amount	Line No.
1	Purchases through MISO	129,689	$ 3,145,030	1
2	Purchased Power other than MISO	(12,579)	$ (405,730)	2
3	NIPSCO Transmission Losses	-	$ -	3
4	**Total Purchased Power Subject to the Benchmark**	**117,110**	**$ 2,739,300**	4
5	Non-Recoverable Purchased Power Costs		$ -	5
6	Recoverable Purchased Power Costs		$ 2,739,300	6

NORTHERN INDIANA PUBLIC SERVICE COMPANY
DETERMINATION OF MISO COMPONENTS OF FUEL COST
FOR THE MONTH OF
OCTOBER 2011

Line No.	Energy Market FAC Adjustment Components	Total OCTOBER 2011	Jurisdictional OCTOBER 2011	Line No.
1	Delta LMP[1]	$ 4,871,151	$ 4,784,900	1
2	FTR (Revenue) / Expenses	$ (3,640,391)	$ (3,560,122)	2
3	RT Marg. Loss Surplus Credit	$ (408,215)	$ (399,203)	3
4	Virtuals Bids and Offers for Load	$ -	$ -	4
5	DA & RAC Recovery of Unit Commitment Costs	$ (239,516)	$ (235,142)	5
6	Inadvertent Energy	$ (164,608)	$ (160,986)	6
7	Ancilliary Services Revenue	$ (70,859)	$ (69,297)	7
8	Ancilliary Services Costs	$ 199,789	$ 195,402	8
9	Ancilliary Services Incentive to Follow Dispatch	$ (1,000)	$ (978)	9
10	Miscellaneous	$ -	$ -	10
11	Total (To Sch 5, line 19)	$ 546,351	$ 554,574	11

Negative amount is a credit to expense (payment from MISO)
Positive amount is a debit to expense (payment to MISO)

1 Differential of MCC and MLC between the load zone and generation pricing nodes

NORTHERN INDIANA PUBLIC SERVICE COMPANY
DETERMINATION OF MISO COMPONENTS OF FUEL COSTS
FOR THE MONTH OF
NOVEMBER 2011

Line No.	Energy Market FAC Adjustment Components	Total NOVEMBER 2011	Jurisdictional NOVEMBER 2011	Line No.
1	Delta LMP[1]	$ 4,215,193	$ 4,152,874	1
2	FTR (Revenue) / Expenses	$ (3,055,496)	$ (2,989,439)	2
3	RT Marg. Loss Surplus Credit	$ (225,268)	$ (220,398)	3
4	Virtuals Bids and Offers for Load	$ -	$ -	4
5	DA & RAC Recovery of Unit Commitment Costs	$ (73,094)	$ (63,732)	5
6	Inadvertent Energy	$ (108,431)	$ (106,087)	6
7	Ancilliary Services Revenue	$ (83,053)	$ (81,258)	7
8	Ancilliary Services Costs	$ 155,529	$ 152,167	8
9	Ancilliary Services Incentive to Follow Dispatch	$ 335	$ 328	9
10	Miscellaneous	$ -	$ -	10
11	Total (To Sch 5, line 19)	$ 825,715	$ 844,455	11

Negative amount is a credit to expense (payment from MISO)
Positive amount is a debit to expense (payment to MISO)

1 Differential of MCC and MLC between the load zone and generation pricing nodes

NORTHERN INDIANA PUBLIC SERVICE COMPANY
DETERMINATION OF MISO COMPONENTS OF FUEL COSTS
FOR THE MONTH OF
DECEMBER 2011

Line No.	Energy Market FAC Adjustment Components		Total DECEMBER 2011		Jurisdictional DECEMBER 2011	Line No.
1	Delta LMP[1]	$	2,053,824	$	1,941,400	1
2	FTR (Revenue) / Expenses	$	49,573	$	46,848	2
3	RT Marg. Loss Surplus Credit	$	(231,937)	$	(219,188)	3
4	Virtuals Bids and Offers for Load	$	-	$	-	4
5	DA & RAC Recovery of Unit Commitment Costs	$	(243,739)	$	(229,361)	5
6	Inadvertent Energy	$	(36,282)	$	(34,288)	6
7	Ancilliary Services Revenue	$	(86,111)	$	(81,378)	7
8	Ancilliary Services Costs	$	141,025	$	133,273	8
9	Ancilliary Services Incentive to Follow Dispatch	$	(1,542)	$	(1,457)	9
10	Miscellaneous	$	-	$	-	10
11	Total (To Sch 5, line 19)	$	1,644,811	$	1,555,849	11

Negative amount is a credit to expense (payment from MISO)
Positive amount is a debit to expense (payment to MISO)

1 Differential of MCC and MLC between the load zone and generation pricing nodes

NORTHERN INDIANA PUBLIC SERVICE COMPANY
MISO CHARGES BY MONTH BY CHARGE TYPE
OCTOBER 2011

LINE NO.	CHARGE TYPE	Trackable	LINE NO.
1	Day Ahead Market Administration Amount	$ -	1
2	Day Ahead Regulation Amount	(22,897)	2
3	Day Ahead Spinning Reserve Amount	(42,830)	3
4	Day Ahead Supplemental Reserve Amount	(568)	4
5	Day Ahead Asset Energy Amount	8,317,537	5
6	Day Ahead Financial Bilateral Transaction Congestion Amount	-	6
7	Day Ahead Financial Bilateral Transaction Loss Amount	-	7
8	Day Ahead Congestion Rebate on Carve-Out Grandfathered Agrmnts	-	8
9	Day Ahead Loss Rebate on Carve-Out Grandfathered Agrmnts	-	9
10	Day Ahead Congestion Rebate on Option B Grandfathered Agrmnts	-	10
11	Day Ahead Loss Rebate on Option B Grandfathered Agrmnts	-	11
12	Day Ahead Non-Asset Energy Amount	-	12
13	Day Ahead Revenue Sufficiency Guarantee Distribution Amount	31,928	13
14	Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	(65,118)	14
15	Day Ahead Schedule 24 Allocation	-	15
16	Day Ahead Virtual Energy Amount	-	16
17	DAY AHEAD SUBTOTAL	$ 8,218,052	17
18	Real Time Market Administration Fee Amount	$ -	18
19	Real Time Contingency Reserve Deployment Failure Charge Amount	-	19
20	Real Time Excessive Energy Amount	(12,536)	20
21	Real Time Excessive/Deficient Energy Deployment Charge Amount	135	21
22	Real Time Net Regulation Adjustment Amount	(1,081)	22
23	Real Time Non-Excessive Energy Amount	741,745	23
24	Real Time Regulation Amount	75	24
25	Real Time Regulation Cost Distribution Amount	106,071	25
26	Real Time Spinning Reserve Amount	(4,246)	26
27	Real Time Spinning Reserve Cost Distribution Amount	67,323	27
28	Real Time Supplemental Reserve Amount	(393)	28
29	Real Time Supplemental Reserve Cost Distribution Amount	25,395	29
30	Real Time Asset Energy Amount	(403,707)	30
31	Real Time Financial Bilateral Transaction Congestion Amount	-	31
32	Real Time Financial Bilateral Transaction Loss Amount	-	32
33	Real Time Congestion Rebate on Carve-Out Grandfathered Agrmnts	-	33
34	Real Time Loss Rebate on Carve-Out Grandfathered Agrmnts	-	34
35	Real Time Distribution of Losses Amount	(408,215)	35
36	Real Time Miscellaneous Amount	-	36
37	Real Time Non-Asset Energy Amount	-	37
38	Real Time Net Inadvertent Distribution Amount	(164,608)	38
39	Real Time Price Volatility Make Whole	(255,363)	39
40	Real Time Revenue Neutrality Uplift Amount	-	40
41	Real Time Revenue Sufficiency Guarantee First Pass Distribution Amount	58,465	41
42	Real Time Revenue Sufficiency Guarantee Make Whole Payment Amount	(9,428)	42
43	Real Time Schedule 24 Allocation	-	43
44	Real Time Schedule 24 Distribution	-	44
45	Real Time Uninstructed Deviation Amount	-	45
46	Real Time Virtual Energy Amount	-	46
47	REAL TIME SUBTOTAL	$ (259,368)	47
48	Financial Transmission Rights Market Administration Amount	$ -	48
49	Financial Transmission Rights Auction Revenue Distribution Amount	(1,636,081)	49
50	Financial Transmission Rights Auction Revenue Transaction Amount	1,445,009	50
51	Financial Transmission Rights Auction Revenue Infeasible Amount	109,537	51
52	Financial Transmission Rights Auction Revenue Excess Distribution Amount	(171,318)	52
53	Financial Transmission Rights Market Full Funding Guarantee	(40,961)	53
54	Financial Transmission Rights Market Guarantee Uplift	76,270	54
55	Financial Transmission Rights Hourly Allocation Amount	(3,338,887)	55
56	Financial Transmission Rights Monthly Allocation Amount	(83,980)	56
57	Financial Transmission Rights Monthly Transaction Amount	-	57
58	Financial Transmission Rights Transaction Amount	-	58
59	Financial Transmission Rights Yearly Allocation Amount	-	59
60	FINANCIAL TRANSMISSION RIGHTS SUBTOTAL	$ (3,640,391)	60
61	Real Time Revenue Neutrality Uplift Amount - Contingency Response Deployment Failure Uplift Carve Out	$ (1,135)	61
62	Real Time Revenue Sufficiency Guarantee First Pass/Second Pass Distribution Amount- Carve Out	-	62
63	Market Administration Virtual and Fin-Phys Carve Out	-	63
64	Real Time Non-Asset Energy Fin Sched Carve-Out	-	64
65	Real Time Non Excessive Energy Carve-Out	-	65
66	Real Time Revenue Neutrality Uplift Amount-Second Pass RSG Carve Out	-	66
67	CARVEOUT SUBTOTAL	$ (1,135)	67
68	GRAND TOTAL	$ 4,317,158	68

NORTHERN INDIANA PUBLIC SERVICE COMPANY
MISO CHARGES BY MONTH BY CHARGE TYPE
NOVEMBER 2011

LINE NO.	CHARGE TYPE	Trackable	LINE NO.
1	Day Ahead Market Administration Amount	-	1
2	Day Ahead Regulation Amount	(18,434)	2
3	Day Ahead Spinning Reserve Amount	(40,347)	3
4	Day Ahead Supplemental Reserve Amount	(2,632)	4
5	Day Ahead Asset Energy Amount	4,724,800	5
6	Day Ahead Financial Bilateral Transaction Congestion Amount	-	6
7	Day Ahead Financial Bilateral Transaction Loss Amount	-	7
8	Day Ahead Congestion Rebate on Carve-Out Grandfathered Agrmnts	-	8
9	Day Ahead Loss Rebate on Carve-Out Grandfathered Agrmnts	-	9
10	Day Ahead Congestion Rebate on Option B Grandfathered Agrmnts	-	10
11	Day Ahead Loss Rebate on Option B Grandfathered Agrmnts	-	11
12	Day Ahead Non-Asset Energy Amount	-	12
13	Day Ahead Revenue Sufficiency Guarantee Distribution Amount	64,426	13
14	Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	(44,972)	14
15	Day Ahead Schedule 24 Allocation	-	15
16	Day Ahead Virtual Energy Amount	-	16
17	DAY AHEAD SUBTOTAL	4,682,941	17
18	Real Time Market Administration Fee Amount	-	18
19	Real Time Contingency Reserve Deployment Failure Charge Amount	-	19
20	Real Time Excessive Energy Amount	977	20
21	Real Time Excessive/Deficient Energy Deployment Charge Amount	704	21
22	Real Time Net Regulation Adjustment Amount	(556)	22
23	Real Time Non-Excessive Energy Amount	1,393,853	23
24	Real Time Regulation Amount	(19,233)	24
25	Real Time Regulation Cost Distribution Amount	95,570	25
26	Real Time Spinning Reserve Amount	(2,515)	26
27	Real Time Spinning Reserve Cost Distribution Amount	40,215	27
28	Real Time Supplemental Reserve Amount	8	28
29	Real Time Supplemental Reserve Cost Distribution Amount	19,744	29
30	Real Time Asset Energy Amount	(648,934)	30
31	Real Time Financial Bilateral Transaction Congestion Amount	-	31
32	Real Time Financial Bilateral Transaction Loss Amount	-	32
33	Real Time Congestion Rebate on Carve-Out Grandfathered Agrmnts	-	33
34	Real Time Loss Rebate on Carve-Out Grandfathered Agrmnts	-	34
35	Real Time Distribution of Losses Amount	(225,268)	35
36	Real Time Miscellaneous Amount	-	36
37	Real Time Non-Asset Energy Amount	-	37
38	Real Time Net Inadvertent Distribution Amount	(108,431)	38
39	Real Time Price Volatility Make Whole	(133,389)	39
40	Real Time Revenue Neutrality Uplift Amount	-	40
41	Real Time Revenue Sufficiency Guarantee First Pass Distribution Amount	71,779	41
42	Real Time Revenue Sufficiency Guarantee Make Whole Payment Amount	(30,938)	42
43	Real Time Schedule 24 Allocation	-	43
44	Real Time Schedule 24 Distribution	-	44
45	Real Time Uninstructed Deviation Amount	-	45
46	Real Time Virtual Energy Amount	-	46
47	REAL TIME SUBTOTAL	453,586	47
48	Financial Transmission Rights Market Administration Amount	-	48
49	Financial Transmission Rights Auction Revenue Distribution Amount	(1,636,060)	49
50	Financial Transmission Rights Auction Revenue Transaction Amount	1,445,009	50
51	Financial Transmission Rights Auction Revenue Infeasible Amount	109,537	51
52	Financial Transmission Rights Auction Revenue Excess Distribution Amount	(170,690)	52
53	Financial Transmission Rights Market Full Funding Guarantee	21,436	53
54	Financial Transmission Rights Market Guarantee Uplift	(57,741)	54
55	Financial Transmission Rights Hourly Allocation Amount	(2,695,232)	55
56	Financial Transmission Rights Monthly Allocation Amount	(71,755)	56
57	Financial Transmission Rights Monthly Transaction Amount	-	57
58	Financial Transmission Rights Transaction Amount	-	58
59	Financial Transmission Rights Yearly Allocation Amount	-	59
60	FINANCIAL TRANSMISSION RIGHTS SUBTOTAL	(3,655,496)	60
61	Real Time Revenue Neutrality Uplift Amount - Contingency Response Deployment Failure Uplift Carve Out	(369)	61
62	Real Time Revenue Sufficiency Guarantee First Pass/Second Pass Distribution Amount- Carve Out	-	62
63	Market Administration Virtual and Fin-Phys Carve Out	-	63
64	Real Time Non-Asset Energy Fin Sched Carve-Out	-	64
65	Real Time Non Excessive Energy Carve-Out	-	65
66	Real Time Revenue Neutrality Uplift Amount-Second Pass RSG Carve Out	-	66
67	CARVEOUT SUBTOTAL	(369)	67
68	GRAND TOTAL	2,060,662	68

NORTHERN INDIANA PUBLIC SERVICE COMPANY
MISO CHARGES BY MONTH BY CHARGE TYPE
DECEMBER 2011

LINE NO.	CHARGE TYPE	Trackable	LINE NO.
1	Day Ahead Market Administration Amount	-	1
2	Day Ahead Regulation Amount	(22,646)	2
3	Day Ahead Spinning Reserve Amount	(39,990)	3
4	Day Ahead Supplemental Reserve Amount	(753)	4
5	Day Ahead Asset Energy Amount	2,556,082	5
6	Day Ahead Financial Bilateral Transaction Congestion Amount	-	6
7	Day Ahead Financial Bilateral Transaction Loss Amount	-	7
8	Day Ahead Congestion Rebate on Carve-Out Grandfathered Agrmnts	-	8
9	Day Ahead Loss Rebate on Carve-Out Grandfathered Agrmnts	-	9
10	Day Ahead Congestion Rebate on Option B Grandfathered Agrmnts	-	10
11	Day Ahead Loss Rebate on Option B Grandfathered Agrmnts	-	11
12	Day Ahead Non-Asset Energy Amount	-	12
13	Day Ahead Revenue Sufficiency Guarantee Distribution Amount	39,910	13
14	Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	(156,397)	14
15	Day Ahead Schedule 24 Allocation	-	15
16	Day Ahead Virtual Energy Amount	-	16
17	**DAY AHEAD SUBTOTAL**	2,376,206	17
18	Real Time Market Administration Fee Amount	-	18
19	Real Time Contingency Reserve Deployment Failure Charge Amount	-	19
20	Real Time Excessive Energy Amount	(1,706)	20
21	Real Time Excessive/Deficient Energy Deployment Charge Amount	360	21
22	Real Time Net Regulation Adjustment Amount	487	22
23	Real Time Non-Excessive Energy Amount	407,230	23
24	Real Time Regulation Amount	(17,608)	24
25	Real Time Regulation Cost Distribution Amount	64,286	25
26	Real Time Spinning Reserve Amount	(5,163)	26
27	Real Time Spinning Reserve Cost Distribution Amount	33,986	27
28	Real Time Supplemental Reserve Amount	47	28
29	Real Time Supplemental Reserve Cost Distribution Amount	22,753	29
30	Real Time Asset Energy Amount	(92,513)	30
31	Real Time Financial Bilateral Transaction Congestion Amount	-	31
32	Real Time Financial Bilateral Transaction Loss Amount	-	32
33	Real Time Congestion Rebate on Carve-Out Grandfathered Agrmnts	-	33
34	Real Time Loss Rebate on Carve-Out Grandfathered Agrmnts	-	34
35	Real Time Distribution of Losses Amount	(231,937)	35
36	Real Time Miscellaneous Amount	-	36
37	Real Time Non-Asset Energy Amount	-	37
38	Real Time Net Inadvertent Distribution Amount	(36,282)	38
39	Real Time Price Volatility Make Whole	(175,948)	39
40	Real Time Revenue Neutrality Uplift Amount	-	40
41	Real Time Revenue Sufficiency Guarantee First Pass Distribution Amount	46,698	41
42	Real Time Revenue Sufficiency Guarantee Make Whole Payment Amount	-	42
43	Real Time Schedule 24 Allocation	-	43
44	Real Time Schedule 24 Distribution	-	44
45	Real Time Uninstructed Deviation Amount	-	45
46	Real Time Virtual Energy Amount	-	46
47	**REAL TIME SUBTOTAL**	36,710	47
48	Financial Transmission Rights Market Administration Amount	-	48
49	Financial Transmission Rights Auction Revenue Distribution Amount	(1,720,110)	49
50	Financial Transmission Rights Auction Revenue Transaction Amount	1,720,104	50
51	Financial Transmission Rights Auction Revenue Infeasible Amount	23,900	51
52	Financial Transmission Rights Auction Revenue Excess Distribution Amount	(130,430)	52
53	Financial Transmission Rights Market Full Funding Guarantee	(2,319)	53
54	Financial Transmission Rights Market Guarantee Uplift	(45,260)	54
55	Financial Transmission Rights Hourly Allocation Amount	267,876	55
56	Financial Transmission Rights Monthly Allocation Amount	(64,188)	56
57	Financial Transmission Rights Monthly Transaction Amount	-	57
58	Financial Transmission Rights Transaction Amount	-	58
59	Financial Transmission Rights Yearly Allocation Amount	-	59
60	**FINANCIAL TRANSMISSION RIGHTS SUBTOTAL**	49,573	60
61	Real Time Revenue Neutrality Uplift Amount - Contingency Response Deployment Failure Uplift Carve Out	(1,922)	61
62	Real Time Revenue Sufficiency Guarantee First Pass/Second Pass Distribution Amount- Carve Out	-	62
63	Market Administration Virtual and Fin-Phys Carve Out	-	63
64	Real Time Non-Asset Energy Fin Sched Carve-Out	-	64
65	Real Time Non Excessive Energy Carve-Out	-	65
66	Real Time Revenue Neutrality Uplift Amount-Second Pass RSG Carve Out	-	66
67	**CARVEOUT SUBTOTAL**	(1,922)	67
68	**GRAND TOTAL**	2,460,567	68

CAUSE NO. 38706-FAC94
EXHIBIT B
SCHEDULE 8

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Determination of Interruptible Credits to be included In FAC
July 2011 through December 2011

LINE NO.		Recoverable Interruptible Credits	LINE NO.
1	July 2011	$ -	1
2	August 2011	$ -	2
3	September 2011	$ -	3
4	October 2011	$ -	4
5	November 2011	$ -	5
6	December 2011	$ 446,402	6
7	TOTAL Recoverable Interruptible Credits	$ 446,402	7
8	FAC Recoverable percentage per Cause No. 43969	25%	8
9	Recoverable Interruptible Credits included in FAC	$ 111,600	9
10	Recoverable Interruptible Credits Variance included in FAC	$ -	10
11	TOTAL Recoverable Interruptible Credits included in FAC	$ 111,600	11
12	Estimated Indiana Jurisdictional Sales (MWH) (Sch 1, Line 11 Total column)	4,069,137	12
13	Recoverable Interruptible Credid Factor - Line 12 divided by Estimated Indiana Jurisdictional Sales (mills/kwh) (to Schedule 1, Line 28)	0.027	13

A6. Petitioner's Exhibit No. 1-A is the Verified Petition filed in this Cause, including Petitioner's Exhibits A and B attached thereto.

Q7. What does Petitioner's Exhibit No. 1-A request?

A7. In its Verified Petition, NIPSCO requests approval of a fuel cost adjustment of (a) $(0.000840~~702~~) per kilowatt hour for customers billed under Rate Schedules 611, 612, 613, 620, 621, 622, 623, 624, 625, 626, 632, 633, 634, 641, 642, 644, 650, 655 and 660, Rate Code 647 and Rider 676 and (b) $0.005429~~567~~ per kilowatt hour for two existing customers billed under Rate Code 647 under contracts approved by the Commission that contain a different base fuel cost and require a special calculation until their expiration, to be applicable during the billing months of May, June and July 2012.

Q8. Please explain Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5 and Petitioner's Exhibit No. 1-B.

A8. Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5 shows actual and forecasted sales and fuel costs in the period October, November and December 2011. Petitioner's Exhibit No. 1-B shows NIPSCO's actual fuel costs for the period January 2007 through December 2011, the last month

<u>Changes under new 600 rates</u>

- The base fuel cost reduction changes to 28.729 mills per kwh.
- Inclusion of recovery of 25% of the actual interruptible credits paid on Rider 675 for the applicable period (same months as FAC reconciliation months).

<u>Schedule 1, page 1 of 2</u>

- There is a new Line 28 to include the factor for the recovery of 25% of the interruptible credits. Credits were paid pursuant to Rider 675 for December 27 – 31, 2011.
- The base cost reduction is updated from 22.556 to 28.729 on Line 29.

<u>Schedule 1, page 2 of 2</u>

- NIPSCO has two existing special contracts, which by their terms expire six months following implementation of new rates, which will be billed under Rate Code 647. The special contracts contain a different base fuel cost and will require a special calculation until their expiration. After that period, which will be no longer than 6 months, it is anticipated that these services will move to Rate 632.
- This Schedule will take the adjusted fuel cost factor on Schedule 1, page 1 Line 29 and reduce it for the 22.556 base cost of fuel~~gas~~ to create the FAC factor for Rate code 647 on Appendix B.

<u>Revised Exhibit 1-C</u>

- Additional lines relating to the Interruptible Credit Recovery have been added.

<u>Customer Credit Adjustment (formerly Appendix C)</u>

- The revenue credit and the sharing mechanism approved in Cause No. 41746 is no longer in effect. NIPSCO anticipates that by the end of January 2012, reconciliations of the revenue credit will be performed for

CAUSE NO. 38706-FAC94
EXHIBIT 1-C

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Comparison of Current Filing and Prior Approved Fuel Cost Factor
Cause No. 38706-FAC94 and Cause No. 38706-FAC 93 Revised

LINE NO.		CONTRIBUTION TO FUEL COST ADJUSTMENT (MILLS/KWH)			LINE NO.
		CAUSE NO. 38706-FAC94	CAUSE NO. 38706-FAC93 Revised	DIFFERENCE	
1	Fuel Cost excluding Variance	29.748 ~~29.884~~	32.596	~~(2.712)~~ (2.848)	1
2	Fuel Cost Variance Adjustment	(1.873)	0.977	(2.850)	2
3	Interruptible Credit Recovery	0.027	0.000	~~0.000~~ 0.027	3
4	Interruptible Credit Recovery Variance Adjustment	0.000	0.000	0.000	4
5	Tax included in calculation	(0.013) ~~(0.011)~~	0.075	~~(0.086)~~ (0.088)	5
6	Total Fuel Cost	27.889 ~~28.027~~	33.648	~~(5.621)~~ (5.759)	6
7	LESS: Base Cost in Base Rates	28.729	28.729	0.000	7
8	TOTAL FUEL COST FACTORS	(0.840) ~~(0.702)~~	4.919	~~(5.621)~~ (5.759)	8

CAUSE NO. 38706-FAC94
EXHIBIT 1-D

NORTHERN INDIANA PUBLIC SERVICE COMPANY

COMPARISON OF CURRENT FILING AND PRIOR APPROVED FUEL COST FACTOR

CAUSE NO. 38706-FAC94 AND CAUSE NO. 38706-FAC93

		ESTIMATED COST		MWH		UNIT COST (MILLS/KWH)		
LINE NO.	SOURCE	CURRENT FILING CAUSE NO. 38706-FAC94	PRIOR FILING CAUSE NO. 38706-FAC93	CURRENT FILING CAUSE NO. 38706-FAC94	PRIOR FILING CAUSE NO 38706-FAC93	CURRENT FILING CAUSE NO. 38706-FAC94	PRIOR FILING CAUSE NO. 38706-FAC93	LINE NO.
1	STEAM GENERATION	$ 109,127,227	$ 118,019,121	3,888,687	3,965,655	28.063	29.760	1
2	NUCLEAR GENERATION	-	-	0	-	-	-	2
3	HYDRO GENERATION	-	-	17,349	16,541	-	-	3
4	OTHER GENERATION	190,950	101,411	3,566	1,466	53.547	69.156	4
5	PURCHASES THROUGH MISO	13,634,340	18,414,444	619,746	557,285	22.000	33.043	5
6	MISO COMPONENTS OF COST OF FUEL	3,951,708	3,228,588	66,051	-	59.828	-	6
7	PURCHASED POWER OTHER THAN MISO	3,245,226	3,027,476		61,591	-	49.154	7
	LESS.							
8	ENERGY LOSSES AND COMPANY USE		-	227,734	233,263	-	-	8
9	INTERSYSTEM SALES THROUGH MISO	~~8,329,604~~ 8,881,156	8,888,359	298,528	201,325	~~27.902~~ 29.750	34.215	9
10	INTERSYSTEM SALES OTHER THAN MISO	-	-	-	-	-	-	10
11	JURISDICTIONAL SALES NOT SUBJECT TO FAC	-	4,173,004	-	133,800	-	31.188	11
12	WIND PPA ADJUSTMENT	217,638	232,845	-	-	-	-	12
13	PURCHASE POWER BENCHMARK ADJUSTMENT	-	-	-	-	-	-	13
14	TOTAL	$ ~~121,602,208~~ 121,050,656	$ 131,496,832	4,069,137	4,034,150	~~29.884~~ 29.748	32.596	14

A6. Petitioner's Exhibit No. 1-A is the Verified Petition filed in this Cause, including Petitioner's Exhibits A and B attached thereto.

Q7. What does Petitioner's Exhibit No. 1-A request?

A7. In its Verified Petition, NIPSCO requests approval of a fuel cost adjustment of (a) $(0.000840) per kilowatt hour for customers billed under Rate Schedules 611, 612, 613, 620, 621, 622, 623, 624, 625, 626, 632, 633, 634, 641, 642, 644, 650, 655 and 660, Rate Code 647 and Rider 676 and (b) $0.005429 per kilowatt hour for two existing customers billed under Rate Code 647 under contracts approved by the Commission that contain a different base fuel cost and require a special calculation until their expiration, to be applicable during the billing months of May, June and July 2012.

Q8. Please explain Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5 and Petitioner's Exhibit No. 1-B.

A8. Petitioner's Exhibit No. 1-A, Exhibit B, Schedule 5 shows actual and forecasted sales and fuel costs in the period October, November and December 2011. Petitioner's Exhibit No. 1-B shows NIPSCO's actual fuel costs for the period January 2007 through December 2011, the last month

<u>Changes under new 600 rates</u>

- The base fuel cost reduction changes to 28.729 mills per kwh.
- Inclusion of recovery of 25% of the actual interruptible credits paid on Rider 675 for the applicable period (same months as FAC reconciliation months).

<u>Schedule 1, page 1 of 2</u>

- There is a new Line 28 to include the factor for the recovery of 25% of the interruptible credits. Credits were paid pursuant to Rider 675 for December 27 – 31, 2011.
- The base cost reduction is updated from 22.556 to 28.729 on Line 29.

<u>Schedule 1, page 2 of 2</u>

- NIPSCO has two existing special contracts, which by their terms expire six months following implementation of new rates, which will be billed under Rate Code 647. The special contracts contain a different base fuel cost and will require a special calculation until their expiration. After that period, which will be no longer than 6 months, it is anticipated that these services will move to Rate 632.
- This Schedule will take the adjusted fuel cost factor on Schedule 1, page 1 Line 29 and reduce it for the 22.556 base cost of fuel to create the FAC factor for Rate code 647 on Appendix B.

<u>Revised Exhibit 1-C</u>

- Additional lines relating to the Interruptible Credit Recovery have been added.

<u>Customer Credit Adjustment (formerly Appendix C)</u>

- The revenue credit and the sharing mechanism approved in Cause No. 41746 is no longer in effect. NIPSCO anticipates that by the end of January 2012, reconciliations of the revenue credit will be performed for

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Comparison of Current Filing and Prior Approved Fuel Cost Factor
Cause No. 38706-FAC94 and Cause No. 38706-FAC 93 Revised

		CONTRIBUTION TO FUEL COST ADJUSTMENT (MILLS/KWH)			
LINE NO.		CAUSE NO. 38706-FAC94	CAUSE NO. 38706-FAC93 Revised	DIFFERENCE	LINE NO.
1	Fuel Cost excluding Variance	29.748	32.596	(2.848)	1
2	Fuel Cost Variance Adjustment	(1.873)	0.977	(2.850)	2
3	Interruptible Credit Recovery	0.027	0.000	0.027	3
4	Interruptible Credit Recovery Variance Adjustment	0.000	0.000	0.000	4
5	Tax included in calculation	(0.013)	0.075	(0.088)	5
6	Total Fuel Cost	27.889	33.648	(5.759)	6
7	LESS: Base Cost in Base Rates	28.729	28.729	0.000	7
8	TOTAL FUEL COST FACTORS	(0.840)	4.919	(5.759)	8

CAUSE NO. 38706-FAC94
REVISED EXHIBIT 1-D

NORTHERN INDIANA PUBLIC SERVICE COMPANY

COMPARISON OF CURRENT FILING AND PRIOR APPROVED FUEL COST FACTOR

CAUSE NO. 38706-FAC94 AND CAUSE NO. 38706-FAC93

		ESTIMATED COST		MWH		UNIT COST (MILLS/KWH)		
LINE NO.	SOURCE	CURRENT FILING CAUSE NO. 38706-FAC94	PRIOR FILING CAUSE NO. 38706-FAC93	CURRENT FILING CAUSE NO. 38706-FAC94	PRIOR FILING CAUSE NO. 38706-FAC93	CURRENT FILING CAUSE NO. 38706-FAC94	PRIOR FILING CAUSE NO. 38706-FAC93	LINE NO.
1	STEAM GENERATION	$ 109,127,227	$ 118,019,121	3,888,687	3,965,655	28.063	29.760	1
2	NUCLEAR GENERATION	-	-	0	-	-	-	2
3	HYDRO GENERATION	-	-	17,349	16,541	-	-	3
4	OTHER GENERATION	190,950	101,411	3,566	1,466	53.547	69.156	4
5	PURCHASES THROUGH MISO	13,634,340	18,414,444	619,746	557,285	22.000	33.043	5
6	MISO COMPONENTS OF COST OF FUEL	3,951,708	3,228,588	66,051	-	59.828	-	6
7	PURCHASED POWER OTHER THAN MISO	3,245,225	3,027,476		61,591	-	49.154	7
	LESS:							
8	ENERGY LOSSES AND COMPANY USE		-	227,734	233,263	-	-	8
9	INTERSYSTEM SALES THROUGH MISO	8,881,156	6,888,359	298,528	201,325	29.750	34.215	9
10	INTERSYSTEM SALES OTHER THAN MISO	-	-	-	-	-	-	10
11	JURISDICTIONAL SALES NOT SUBJECT TO FAC	-	4,173,004	-	133,800	-	31.188	11
12	WIND PPA ADJUSTMENT	217,638	232,845	-	-	-	-	12
13	PURCHASE POWER BENCHMARK ADJUSTMENT	-	-	-	-	-	-	13
14	TOTAL	$ 121,050,656	$ 131,496,832	4,069,137	4,034,150	29.748	32.596	14