Exhibit No.:	
Issue:	Revenue Requirement
Witness:	Nicholas L. Phillips
Type of Exhibit:	Surrebuttal Testimony
Sponsoring Party:	MIEC
Case No.:	ER-2014-0258
Date Testimony Prepared:	February 6, 2015

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	**)))))**	**Case No. ER-2014-0258**

Surrebuttal Testimony of

Nicholas L. Phillips

On behalf of

Missouri Industrial Energy Consumers

NON-PROPRIETARY VERSION

February 6, 2015

Brubaker & Associates, Inc.

Project 9913

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	)))))	**Case No. ER-2014-0258**

STATE OF MISSOURI	)	
	)	**SS**
COUNTY OF ST. LOUIS	)	

Affidavit of Nicholas L. Phillips

Nicholas L. Phillips, being first duly sworn, on his oath states:

1. My name is Nicholas L. Phillips. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Missouri Industrial Energy Consumers in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my surrebuttal testimony which was prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2014-0258.

3. I hereby swear and affirm that the testimony is true and correct and that it shows the matters and things that it purports to show.

Nicholas L. Phillips
Nicholas L. Phillips

Subscribed and sworn to before me this 5th day of February, 2015.

Maria E. Decker
Notary Public

MARIA E. DECKER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis City
My Commission Expires: May 5, 2017
Commission # 13706793

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<u>Surrebuttal Testimony of Nicholas L. Phillips</u>

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OF THE STATE OF MISSOURI

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Surrebuttal Testimony of Nicholas L. Phillips

I. Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Nicholas L. Phillips. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q ARE YOU THE SAME NICHOLAS L. PHILLIPS WHO HAS PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING ON BEHALF OF MISSOURI INDUSTRIAL ENERGY CONSUMERS ("MIEC")?

A Yes, I am.

Q WHAT IS THE SUBJECT OF YOUR SURREBUTTAL TESTIMONY?

A My surrebuttal testimony is to respond to portions of the Company's rebuttal testimony. First, I respond to Mr. Wills' additional adjustment to annualize electric demands at the Noranda Aluminum, Inc. ("Noranda") smelter. Next, I respond to Mr. Peters and Mr. Haro with respect to the calculation of Net Fuel Cost ("NFC") and Net Base Energy Cost ("NBEC"). Finally, I respond to Mr. Michels with respect to the forecasted wholesale market energy prices for energy he used in his forecasted market price-based estimate of the Actual Net Energy Cost “(ANEC”) and other load based MISO charges that would be avoided if Noranda’s facility were to shut down.

The fact that I do not address a particular issue should not be interpreted as approval of any position taken by Ameren Missouri.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A My conclusions and recommendations are as follows:

1. The recent reduction in electric demands at Noranda is temporary and Noranda should resume more typical electric usage by the end of March 2015. Consequently, it would be improper to assume Noranda’s temporary decrease in electricity consumption is normal. As such, Noranda’s billing determinants should reflect its expected normal usage.

2. MIEC generally agrees with the Company that the adjustments made to the NBEC for Bilateral Off-System Energy Sales Margins, Financial Swap Margins, Net Load and Generation Forecast Error,[1] and RT-RSG-MWP Margins represent incremental refinements to the production cost modeling used for the calculation of NFC. These refinements are made to reflect additional cash flows that are not captured within the production cost models. MIEC agrees that it is appropriate to include each of the four aforementioned adjustments (as corrected) to the NBEC established in this rate case.

3. MIEC agrees with the Company that the estimated net load and generation forecasting error calculation contained in my direct testimony did not capture the necessary change in fuel costs that occur when real time generation levels deviate from day-ahead awards.

4. MIEC has reviewed the calculation for the RT-RSG-MWP and agrees that the RT-RSG-MWP margin percentage had been misapplied in previous rate cases and should have only been applied to Total RSG and Deviation Revenues net of Price Volatility and Regulation Adjustments.

5. The Company’s wholesale energy market price forecast used to compare the reasonableness of Noranda’s rate proposal against future expectations for power prices relies on stale market assumptions and consequently produces results inconsistent with the market’s current future expectations for power prices. Revising these outdated assumptions with current market expectations demonstrates that the energy prices embedded in the later years of the Company’s forecasted wholesale energy market price based avoided cost estimate are excessively high. My revisions lower the seven year

[1]This is also referred to as Real-Time Load and Generation Deviation cost.

forecasted wholesale energy market price from **______** per MWh to $30.33 per MWh.

6. There is evidence that a positive risk premium is priced into forward wholesale electricity contracts. Removal of this risk premium from forward market quotes necessarily corrects for a bias when forward contract prices are used as a surrogate forecast of future spot prices. Removing the risk premium from quoted forward contract prices reduces the seven year forecasted wholesale energy market price from $30.33 per MWh to $29.03 per MWh. My colleague Mr. Dauphinais has implemented my revisions in his surrebuttal testimony.

II. The Noranda Smelter Load

Q PLEASE DESCRIBE THE ELECTRIC USAGE AT THE NORANDA SMELTER.

A Noranda is Ameren Missouri's single largest electric customer and during normal operations, Noranda represents over 10% of the total energy sales made by Ameren Missouri. As noted in the rebuttal testimony of Mr. Wills, Noranda's usage began to decline in mid 2014 to a lower level, atypical of Noranda's historical usage. However, as I will discuss later in this testimony, Noranda fully expects to start increasing its electric usage and return to normal operations by the end of March 2015.

Q PLEASE DESCRIBE THE ADJUSTMENT MADE TO NORANDA'S BILLING DETERMINANTS BASED ON ITS RECENT TEMPORARY REDUCTION IN ELECTRIC USAGE.

A The Company has assumed that Noranda's reduction in electric usage is permanent. Furthermore, the Company has annualized Noranda's demand and energy using only *two* months of data. Both of these assumptions are faulty and must be corrected to ensure consistency and equity are preserved.

Q HAS NORANDA PROVIDED ANY INFORMATION DISCUSSING CIRCUMSTANCES WHICH CAUSED A DECREASE IN ELECTRICITY CONSUMPTION?

A Yes, in response to MPSC Staff Data Request 0564, Noranda provided the follow statement:

> "*Noranda has experienced higher than normal pot failures since around mid-2014 which have led to lower production levels and therefore lower electricity consumption. Noranda is currently estimating to be back to full production by the end of March 2015. This is the only circumstance known to have materially affected power usage during the specified time period.*"

Q WHAT DO YOU RECOMMEND USING FOR BILLING DETERMINANTS FOR NORANDA?

A I recommend using Noranda's actual test year billing determinants for demand and energy. During the test year, Noranda consumed approximately 4.2 million MWh, with a load factor of roughly 98%.[2]

III. Incremental Adjustments to NBEC

Q PLEASE SUMMARIZE THE COMPANY'S RESPONSE REGARDING THE INCREMENTAL ADJUSTMENTS TO THE NBEC YOU RECOMMENDED IN YOUR DIRECT TESTIMONY.

A In my direct testimony, I proposed four adjustments to the NBEC to account for cash flows that are not captured in the production cost modeling used to determine NFC. These four items are: (i) RT-RSG-MWP Margins, (ii) Bilateral Off-System Energy

[2]Workpaper of Steven Wills, "Copy of UE_REB-UE_REB_027_Wills-Att-Noranda load annualization.xlsx".

Sales Margins, (iii) Financial Swap Margins, and (iv) Net Load and Generation Forecasting Error.

Generally speaking, the Company characterizes these adjustments similar to other adjustments that are made to the production cost model results, which incrementally improves the NBEC calculation.[3] The Company equates the adjustments made to the NBEC for Other Sales Revenue[4] to those that I estimated in my direct testimony for RT-RSG-MWP Margins, Bilateral Off-System Energy Sales Margins, Financial Swap Margins, and Net Load and Generation Forecasting Error, arguing they are made for the same purpose.[5] In the Company's opinion, either all of the adjustments (RT-RSG-MWP Margins, Real-Time Load and Generation Deviations, and Bilateral and Swap Margins) should be included (given the appropriate corrections are made to the calculations and the final value should be determined at the end of the true-up period and reflect a consistent treatment of the Polar Vortex) or none should be included.[6]

Q DO YOU AGREE WITH THE COMPANY THAT THE ADJUSTMENTS FOR RT-RSG-MWP MARGINS, REAL-TIME LOAD AND GENERATION DEVIATIONS, AND BILATERAL AND SWAP MARGINS SHOULD BE A PACKAGE DEAL?

A I agree with the Company that all of these adjustments should be made in this rate case, subject to correcting the calculations, consistent treatment of the Polar Vortex and final values being determined at the end of the true-up period. However, given the Company's testimony regarding equitable treatment for all "outside the model"

[3]Rebuttal Testimony of Jaime Haro at Page 3.

[4]Off-system sales of capacity, MISO ancillary service revenues and MISO Day 2 revenues (including MISO RSG Make Whole Payment Margins. (Direct Testimony of Laura Moore at 29-30, Direct Testimony of Mark Peters at 2-3 and Direct Testimony of Jaime Haro at 3-5).

[5]Rebuttal Testimony of Jaime Haro at Page 3.

[6]Rebuttal Testimony of Jaime Haro at Pages 5-6.

adjustments made to the NFC when establishing the NBEC, in future proceedings, MIEC reserves the right to review whether when taken as a whole, if all "outside the model" adjustments to the NFC can be reasonably expected to consistently or reliably improve the accuracy of the NBEC, or whether it is more reasonable to remove all non-NFC costs from the determination of the NBEC and the FAC.

Q YOU DISCUSSED THAT THE COMPANY HAS IDENTIFIED CORRECTIONS THAT SHOULD BE MADE TO THE ESTIMATES OF RT-RSG-MWP MARGINS AND REAL-TIME LOAD AND GENERATION DEVIATION, CAN YOU PLEASE DISCUSS THE COMPANY'S CONCERNS?

A The Company has identified two errors in the calculations used to estimate the value for RT-RSG-MWP Margins and Real-Time Load and Generation Deviation cost. Both errors have actually occurred in previous rate cases.[7] I have reviewed these calculations and the corresponding testimony of Mr. Peters, and I agree that these fundamental errors require correction. The error related to the RT-RSG-MWP Margin, as Mr. Peters discusses, appears to be a simple misapplication of the Company's calculation of the RT-RSG-MWP Margin percentage.[8] The error related to the Real-Time Load and Generation Deviation cost relates to changes in fuel cost due to changes in generation that occur between the day-ahead award and real-time operations.[9] I agree with the Company that both of these errors, while contained in the estimated values used in previous rate cases, require correction when determining any estimated values to use in the calculation of NBEC.

[7]Rebuttal Testimony of Mark Peters at Pages 9,12.
[8]Rebuttal Testimony of Mark Peters at Pages 11-12.
[9]Rebuttal Testimony of Mark Peters at Pages 6.

Q HAS MIEC DISCUSSED A POSSIBLE RESOLUTION RELATED TO THE AREAS OF DISAGREEMENT BETWEEN THE COMPANY, MPSC STAFF AND MIEC?

A Yes. MIEC has been involved in ongoing discussions with both the Company and MPSC Staff related to the areas of disagreement surrounding the calculation of NFC and NBEC. While most of these issues seem to be resolved, MIEC has concerns with the adjusted billing determinants for the Noranda load as well as the wholesale transmission expense and revenue related issues discussed by my colleague Mr. Dauphinais. We will continue to work with the Company, MPSC Staff and any other interested party(s) toward trying to achieve a stipulation and agreement regarding NBEC.

Q WHAT DO YOU RECOMMEND REGARDING THE INCREMENTAL ADJUSTMENTS USED WHEN CALCULATING THE NBEC IN THIS PROCEEDING?

A I recommend including corrected estimates for RT-RSG-MWP Margins, Real-Time Load and Generation Deviation Costs, and Bilateral and Swap Margins when determining the NBEC. Furthermore, these estimates should reflect data through the end of the true up period and a consistent treatment of the Polar Vortex.

<u>IV. The Noranda Price Analysis</u>

Q PLEASE DESCRIBE THE COMPANY'S METHOD FOR ASSESSING THE REASONABLENESS OF NORANDA'S RATE PROPOSAL.

A Generally speaking, the Company contends the most appropriate way to test the reasonableness of Noranda's Rate Proposal is to compare the expected revenues the Company would earn from Noranda under the rate proposal versus the revenues the Company expects it could realize through wholesale market off-system sales in the absence of Noranda's load.[10] The specific assumptions that the Company has used to measure the market based off-system sales expectation have changed from the original analysis the Company put forth in Case No. EC-2014-0224, both in terms of the source of the forward expectations as well as the magnitude of the prices.

The original analysis presented by the Company in Case No. EC-2014-0224, forward wholesale electricity market prices for the Indiana Hub (the primary trading hub in the MISO market and the one most applicable to Ameren Missouri) for calendar years 2015-2018, served as the Company's benchmark for reasonableness.[11] These energy prices were then compared to the energy prices embedded within Noranda's Rate Proposal and estimated revenues were calculated under Noranda's Rate Proposal and the forward market pricing scenarios. The Company also presented a secondary analysis in Case. No. EC-2014-0224 following the same general method as the first analysis; however, rather than rely on forward market prices for electricity, the Company substituted its own IRP projections for wholesale capacity and energy prices.

In the current proceeding, the Company claims it has updated the analysis it presented in Case No. EC-2014-0224. It is true that the Company has presented an analysis similar to the secondary IRP based analysis from Case No. EC-2014-0224; however, the Company has not presented an updated version of its forward market analysis. Furthermore, the IRP analysis has not updated the wholesale energy prices, which the Company developed using assumptions dating back to late 2013. In reality, the "updated" IRP analysis has only shortened the horizon of the study

[10]Rebuattal Testimony of Matt Michels at Pages 28-29.
[11]Rebuattal Testimony of Matt Michels EC-2014-0224 at Pages 24.

period from 10 years to 7 years, and refined some minor estimates related to MISO settlement charges, which in total are a fraction in magnitude compared to the energy costs.

Q IS IT APPROPRIATE TO RELY ON A FORECAST WITH ASSUMPTIONS THAT ARE OVER A YEAR OLD?

A Certain assumptions are more sensitive to time than others and the process of compiling data and producing a forecast is time consuming. Absent these limitations, updating forecasts as frequently as possible would be ideal but pragmatically this is impractical if not impossible. The commodity related pieces of the forecast (i.e., fuel & energy costs predominately) will be the most sensitive to daily changes in market conditions. Fortunately, there are liquid forward markets for fuel and electricity commodities, updated on most business days every year. Each day the participants making or trading in these forward markets use all the available information that exists up to that point in time, including expectations about future supply, demand and other related micro and macroeconomic components to determine what they would be willing to pay for energy in the future. If we compare the natural gas prices that the Company relied on when deriving its forward power curve, we can see that the Company's prices are based on gas prices much higher in cost than the current forward market for natural gas. It comes as no surprise that the forward power curve generated from an overstated gas curve is equally flawed. Table NLP-1 below summarizes the natural gas price differentials.

Table NLP-1

Henry Hub Natural Gas Comparison

	Price			Annual Change	
Year	**Ameren 2014 IRP ($/MMBtu)**	**Forward Price (60 Day Average) ($/MMBtu)**	**Year**	**Ameren 2014 IRP (%)**	**Forward Price (60 Day Average) (%)**
2015	**______**	$3.24	2015		
2016	**______**	$3.56	2016	9.44%	10.08%
2017	**______**	$3.80	2017	4.43%	6.63%
2018	**______**	$3.95	2018	6.76%	3.93%
2019	**______**	$4.08	2019	5.03%	3.38%
2020	**______**	$4.21	2020	5.19%	3.04%
2021	**______**	$4.32	2021	5.81%	2.70%
2022	**______**	$4.44	2022	6.74%	2.82%

Q WHAT ARE THE CURRENT FORWARD MARKET EXPECTATIONS FOR ELECTRICITY AT THE MISO INDIANA HUB?

A As of February 1, 2015, the current annual forward prices for electricity at Indiana Hub (basis adjusted to the AMMO.UE CP Node[12]) were $26.73, $27.70, $28.17, $29.58, $30.65, $32.77, $33.39 and $34.82 for the years 2015, 2016, 2017, 2018, 2019, 2020, 2021 and 2022, respectively. These values are tabulated in Table NLP-2 below.

[12]AMMO.UE is the MISO pricing node where the Company clears its load in the MISO market.

Table NLP-2

Wholesale Market Electricity Comparison

	Price			Annual Change	
Year	Ameren 2014 IRP ($/MWh)	Forward Price (60 Day Average) ($/MWh)	Year	Ameren 2014 IRP (%)	Forward Price (60 Day Average) (%)
2015	**______**	$26.73	2015		
2016	**______**	$27.70	2016	8.03%	3.63%
2017	**______**	$28.17	2017	7.15%	1.71%
2018	**______**	$29.58	2018	8.84%	4.99%
2019	**______**	$30.65	2019	5.80%	3.65%
2020	**______**	$32.77	2020	7.66%	6.90%
2021	**______**	$33.39	2021	6.07%	1.89%
2022	**______**	$34.82	2022	8.56%	4.30%

Q HAVE YOU PERFORMED A MORE DETAILED ANALYSIS SURROUNDING THE FORWARD POWER MARKET?

A Yes. In addition to comparing the Company's 2014 IRP prices to the current market expectations, I have also performed an Ex-Post risk premium analysis comparing historical forward market quotes to the actual observed spot price occurring at the time of maturity for the forward market prices.

Q PLEASE SUMMARIZE YOUR ANALYSIS.

A I began my analysis by gathering hourly wholesale spot electricity prices from April 1, 2005 through December 31, 2014 for the Cinergy Hub and Indiana Hub pricing nodes.[13] I then calculated a monthly On-Peak, Off-Peak and

[13]LMP data obtained from www.misoenergy.org.

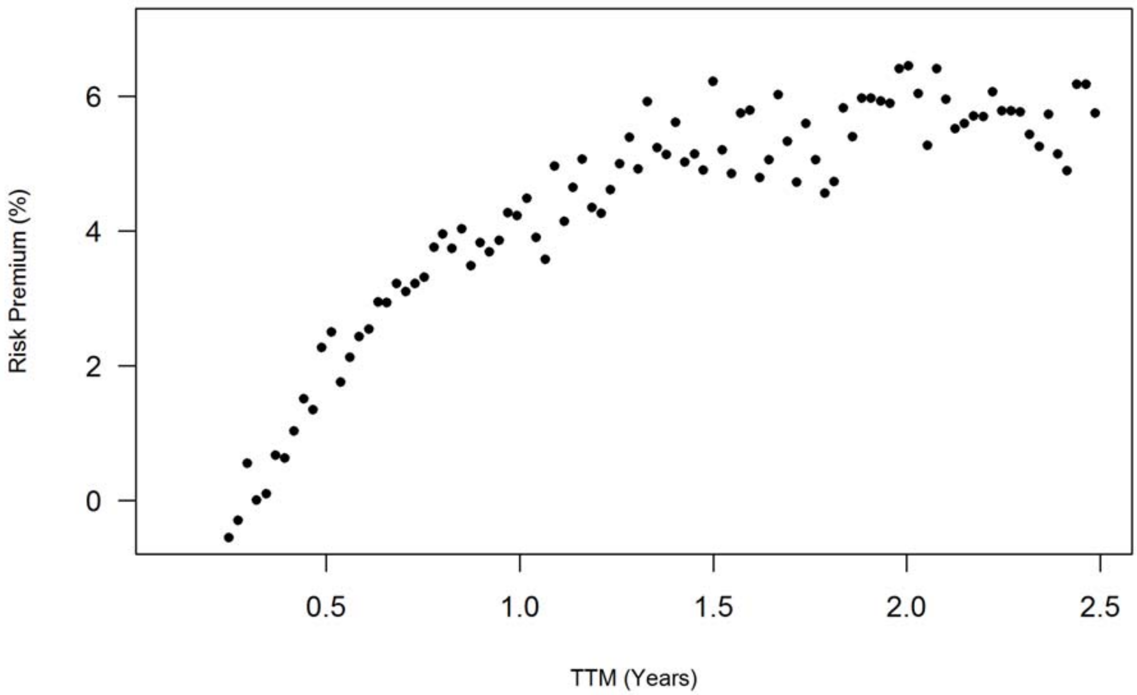
Around-the-Clock average spot price for each month for the period of time from April 2005 through December 2014.

I also obtained historical forward electricity prices for the Cinergy and Indiana Hub delivery locations that traded between June 28, 2002 and December 31, 2014.[14,15] Using this data, I calculated the Time-To-Maturity ("TTM") in years, for each historical price quote, by taking the time difference in days between the trading date and the last day of the delivery month and dividing by 365. In addition, I calculated the difference between each historical forward price quote and the realized spot price for the delivery month.

Using the results of these calculations, I first ranked the data from lowest to highest TTM. Next, I divided the data into approximately equal sized groups of observations.[16] Finally, I calculated the average risk premium for each group. A plot of the results for the On-Peak data is presented in Figure NLP-1 below.

[14]Historical forward prices obtained from Platts & SNL Financial.
[15]On-Peak data from 6/28/2002 – 12/31/2014. Off-Peak data from 1/31/2007-12/31/2014.
[16]Up to a maximum TTM of 2.5 Years.

Figure NLP-1
Ex-Post Risk Premium vs Time-to-Maturity
(On-Peak)

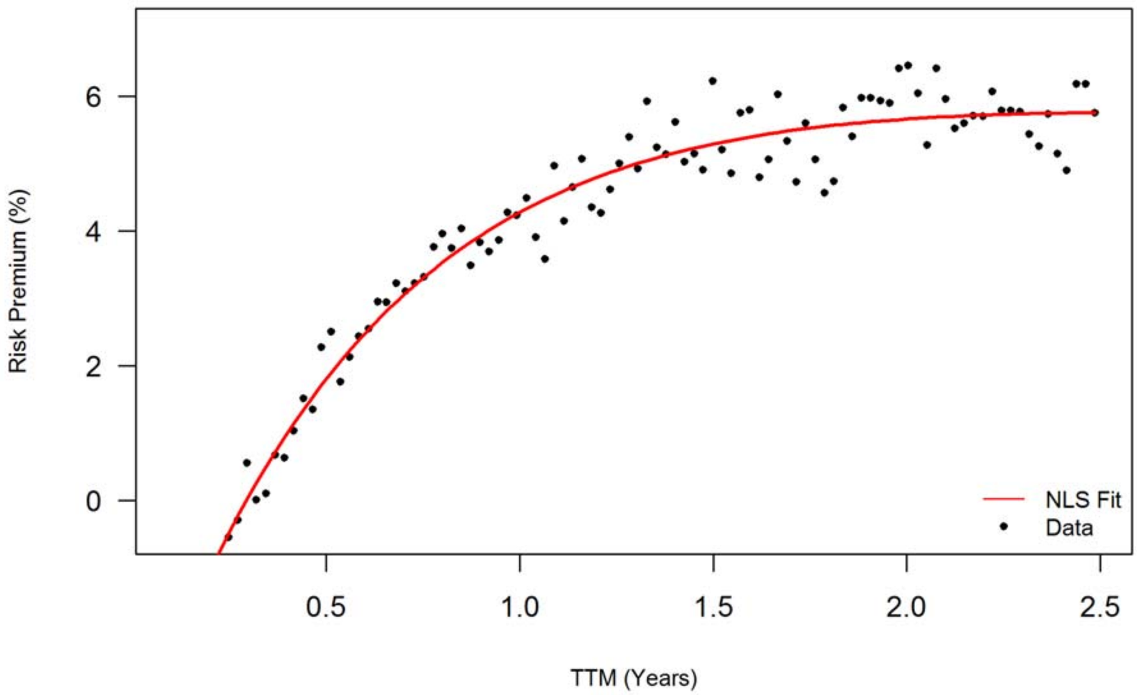


There is an obvious positive risk premium (from the perspective of the long position), that increases with TTM. Similar but smaller risk premiums are observed in the Off-Peak data.[17]

Finally, I fit the Nelson-Siegel-Svensson (”NSS”) model to this data using a method known as Non-Linear Least Squares (“NLS”). Once I fit the model, I extrapolated the estimated risk premium out to a maximum TTM of 7.5 years. The resulting risk premium model is presented in Figure NLP-2 below.

[17] See Appendix B.

Figure NLP-2
Ex-Post Risk Premium vs Time-to-Maturity
(On-Peak)



Q WHAT CAN YOU INFER FROM THESE RESULTS?

A The results of my analysis show that the forward wholesale electricity market contains a positive risk premium (or forecast bias) from the perspective of a market participant taking the long (purchasing) position. This phenomenon does have an intuitive explanation. First, and foremost, forward and futures contracts serve as hedging instruments. The party taking the long position (purchasing the contract) is hedging a future cost by transferring the future price risk to the party taking the short position (selling the contract). This exchange of risk comes with a price in the form of an embedded risk premium built into the forward price.

The second important piece of information that can be inferred from the results is that the forward market prices for electricity tend to be above the expected future spot price of electricity and thereby converge down towards the expected spot price as the time to delivery decreases. That is not to say the forward wholesale electricity market prices always exhibit this behavior, but typically (including at equilibrium), the forward price will manifest this way. This again makes intuitive sense from the perspective of a risk premium. If the market is at a state of equilibrium, the forecast error will be minimal, but there will still exist a risk premium embedded within the forward price that increases with TTM. Absent any new shock/information in the market, the risk premium will slowly reduce as TTM decreases.

Q SHOULD AN ADJUSTMENT BE MADE TO REFLECT THIS RISK PREMIUM IF THE FORWARD MARKET PRICES ARE USED AS A SURROGATE FOR FUTURE SPOT PRICES?

A Yes. In my opinion, the forward market risk premium exists due to the primary function of the forward contracts as hedging instruments. In order to use these forward prices as an expectation for spot prices, the risk premium must be removed to produce an unbiased estimate. Inevitably, there will still be forecast error even if the risk premium is removed; however, these errors should now be unbiased.

Q WHAT ARE THE 60-DAY AVERAGE, RISK ADJUSTED FORWARD WHOLESALE PRICES FOR THE DELIVERY BETWEEN 2015 AND 2022?

A Using the results from my analysis and applying the risk premium adjustment to the basis adjusted 60-day average forward price found in Table NLP-2 above, I have computed calendar year risk adjusted forward energy prices in Table NLP-3 below. Additionally, I have converted these prices into Planning Year prices (tabulated in Table NLP-4 below) which are use by my colleague Mr. Dauphinais.

Table NLP-3

Risk Adjusted Wholesale Market Electricity Comparison

Year	Ameren 2014 IRP ($/MWh)	Forward Price (60 Day Average) ($/MWh)	Year	Risk Adjustment (%)	Risk Adjusted Forward Price (60 Day Average) ($/MWh)
2015	**______**	$26.73	2015	0.64%	$26.56
2016	**______**	$27.70	2016	3.89%	$26.62
2017	**______**	$28.17	2017	4.60%	$26.87
2018	**______**	$29.58	2018	4.64%	$28.20
2019	**______**	$30.65	2019	4.68%	$29.22
2020	**______**	$32.77	2020	4.72%	$31.22
2021	**______**	$33.39	2021	4.76%	$31.80
2022	**______**	$34.82	2022	4.80%	$33.15

Table NLP-4

Risk Adjusted Wholesale Market Electricity Comparison

Year	Ameren 2014 IRP ($/MWh)	Forward Price (60 Day Average) ($/MWh)	Year	Risk Adjustment (%)	Risk Adjusted Forward Price (60 Day Average) ($/MWh)
PY15/16	**______**	$27.13	PY15/16	2.01%	$26.58
PY16/17	**______**	$27.89	PY16/17	4.19%	$26.72
PY17/18	**______**	$28.75	PY17/18	4.62%	$27.42
PY18/19	**______**	$30.02	PY18/19	4.66%	$28.62
PY19/20	**______**	$31.53	PY19/20	4.70%	$30.05
PY20/21	**______**	$33.02	PY20/21	4.74%	$31.46
PY21/22	**______**	$33.98	PY21/22	4.78%	$32.36
Ave	**______**	$30.33	Ave	4.24%	$29.03

Q HOW DO THESE RISK ADJUSTED FORWARD ENERGY PRICES COMPARE TO THE COMPANY'S ESTIMATES USED IN THE NORANDA PRICE ANALYSIS?

A The Company's estimates actually start out slightly lower than the current 60-day average risk adjusted forward wholesale price; however, the Company's forecast grows much fast than the current market expectations. This is in large part due to the outdated natural gas price assumptions I discussed earlier in this testimony. The Company's annual gas and electricity prices are nearly perfectly correlated and as shown in Tables NLP-1 & NLP-2 above, the Company's expected natural gas prices and consequently its expected energy prices grow well in excess of forward market expectations.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A My conclusions and recommendations are as follows:

1. The recent reduction in electric demands at Noranda is temporary and Noranda should resume more typical electric usage by the end of March 2015. Consequently, it would be improper to assume Noranda's temporary decrease in electricity consumption is normal. As such, Noranda's billing determinants should reflect its expected normal usage.

2. MIEC generally agrees with the Company that the adjustments made to the NBEC for Bilateral Off-System Energy Sales Margins, Financial Swap Margins, Net Load and Generation Forecast Error,[18] and RT-RSG-MWP Margins represent incremental refinements to the production cost modeling used for the calculation of NFC. These refinements are made to reflect additional cash flows that are not captured within the production cost models. MIEC agrees that it is appropriate to include each of the four aforementioned adjustments (as corrected) to the NBEC established in this rate case.

3. MIEC agrees with the Company that the estimated net load and generation forecasting error calculation contained in my direct testimony did not capture the necessary change in fuel costs that occur when real time generation levels deviate from day-ahead awards.

4. MIEC has reviewed the calculation for the RT-RSG-MWP and agrees that the RT-RSG-MWP margin percentage had been misapplied in previous rate

[18]This is also referred to as Real-Time Load and Generation Deviation cost.

cases and should have only been applied to Total RSG and Deviation Revenues net of Price Volatility and Regulation Adjustments.

5. The Company's wholesale energy market price forecast used to compare the reasonableness of Noranda's rate proposal against future expectations for power prices relies on stale market assumptions and consequently produces results inconsistent with the market's current future expectations for power prices. Revising these outdated assumptions with current market expectations demonstrates that the energy prices embedded in the later years of the Company's forecasted wholesale energy market price based avoided cost estimate are excessively high. My revisions lower the seven year forecasted wholesale energy market price from **______** per MWh to $30.33 per MWh.

6. There is evidence that a positive risk premium is priced into forward wholesale electricity contracts. Removal of this risk premium from forward market quotes necessarily corrects for a bias when forward contract prices are used as a surrogate forecast of future spot prices. Removing the risk premium from quoted forward contract prices reduces the seven year forecasted wholesale energy market price from $30.33 per MWh to $29.03 per MWh. My colleague Mr. Dauphinais has implemented my revisions in his surrebuttal testimony.

Q DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A Yes.