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Witness: Timothy D. Finnell
Sponsoring Party: Union Electric Company
Type of Exhibit: Rebuttal Testimony
Case No.: ER-2011-0028
Date Testimony Prepared: March 25, 2011

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2011-0028

REBUTTAL TESTIMONY

OF

TIMOTHY D. FINNELL

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
March, 2011

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REBUTTAL TESTIMONY

OF

TIMOTHY D. FINNELL

CASE NO. ER-2011-0028

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Timothy D. Finnell. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, MO 63103.

Q. By whom and in what capacity are you employed?

A. I am employed by Ameren Services Company as a Managing Supervisor, Operations Analysis in the Corporate Planning Function.

Q. Are you the same Timothy D. Finnell who filed direct testimony in this case?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to: (1) explain why Missouri Industrial Energy Consumer's ("MIEC") witness James Dauphinais' proposed changes to several generating unit capabilities used in the production cost model are incorrect; (2) correct the Sioux coal blend cost calculated by the Staff, and (3) point out problems with the Staff's calculation of normalized hourly power prices used in the production cost model to develop normalized net fuel costs.

II. MIEC REBUTTAL

Q. What areas of disagreement do you have with MIEC witness Dauphinais?

A. Mr. Dauphinais' direct testimony states that the Company incorrectly modeled the Callaway, Sioux, and Osage plant ratings and that the ratings of these plants should be increased.

Q. Is Mr. Dauphinais' recommended Callaway rating correct?

A. No. Mr. Dauphinais used actual unit net generation data from 2009 to determine his Callaway rating. Mr. Dauphinais calculated a 12-month average rating of 1,229 net megawatts (MW), which is higher than the unit rating prepared by the Callaway performance engineering group (1,224 net MW). Schedule TDF-ER7 contains the 2009, 2010, and 2011 plant rating information prepared by Brian Pae, Thermal Performance Engineer at Callaway.

Q. Why is there a difference between the ratings calculated by Mr. Pae and the 2009 performance?

A. Callaway's rating is very temperature sensitive. Schedule TDF-ER7 shows the monthly ratings prepared by Mr. Pae and illustrates how the output changes with temperature. In January, the coldest month, the rating is 1,234 net MW and in July, the hottest month, the rating is 1,197 net MW. During 2009 the Callaway plant performed better than its normal rating due to the cooler than normal circulating water temperatures.

The plant rating tables prepared by Mr. Pae are based on five years of temperature data rather than temperature data from a single year. The use of five years of temperature data is a better method for calculating normalized unit ratings and prevents significant rating changes that would occur if temperature data from a single year was used. For the same reason that billing units in a rate case are determined using normalized weather conditions (i.e., to eliminate the effects of hotter or cooler than normal weather in the test year) the

Callaway rating used by the production cost model should be based upon ratings calculated using multi-year temperature information. The latest information the Company has is the 2011 Callaway Plant Capability Report, which I have included as the last page of Schedule TDF-ER7. It reflects an average annual rating of 1,224 net MW. The 1,224 net MW rating, based upon the latest available information and using multi-year temperature information is reflective of a normal level of capability for Callaway and this value should be used instead of the abnormally high value used by Mr. Dauphinais.

Q. Did the Company incorrectly model the Callaway plant outage rates when it combined the full and partial outage rates into a single unplanned outage rate of 3.5%, as Mr. Dauphinais contends?

A. No. The Company did not model the Callaway outage rates incorrectly. Rather, it simply used one of several PROSYM outage modeling methods. For the Callaway Plant, the Company chose to model the plant's full and partial outages using the PROSYM "EFOR" variable rather than to use separate variables for full and partial outages. This outage modeling method is appropriate because the Callaway partial outage rate is very small, 0.5%, and the Callaway plant typically runs at full load, which means that whether a partial outage is modeled as a derate or as a full outage will not result in a significant change to the production cost model results.

Q. Given the foregoing, should Mr. Dauphinais' adjustments relating to Callaway inputs be made?

A. No. The net fuel costs I have presented in this testimony accurately model the impact of Callaway generation on net fuel costs.

Q. Why is Mr. Dauphinais' recommendation regarding the Sioux unit ratings incorrect?

A. Mr. Dauphinais calculated the normalized Sioux rating (pre-scrubber) based on historical data from 2009. Had the coal quality used at Sioux in 2009 been normal, his approach may have produced reasonable results. However, the coal quality in 2009 was not normal, and it was substantially different in the test year and is expected to remain different.

Q. How does the coal quality impact the Sioux units' ratings?

A. For the Sioux Plant, as well as other plants, the generator output is a function of the amount of fuel, measured in British thermal units (Btus), input into the boiler. The lower the Btu content of the coal, the lower the generator output.

An example of the fuel input and generator output relationship is shown in Schedule TDF-ER8, which illustrates the impact of coal blending on Sioux unit capability. Sioux is the only Ameren Missouri coal-fired generating plant that has not been converted to 100% Powder River Basin ("PRB"), Wyoming coal. Consequently, it must blend PRB coal with Illinois coal. One method of changing the amount of fuel input to the boiler is to change the fuel blend or mix of low Btu coal (PRB) and high Btu coal (Illinois coal). Each row in Schedule TDF-ER8 represents a different Btu value as calculated for a specific coal blend and the associated unit capability. The first row is a 100% PRB and 0% Illinois coal blend, which has an average coal quality of 8,810 Btu/lb. and results in a unit capability of 402 net MW (pre-scrubber) or 394 net MW (post-scrubber). The plant cannot operate for long periods of time using a 100% PRB / 0% Illinois coal blend without running into operating issues. In order to avoid operating problems associated with burning 100% PRB coal, the Company tries to operate the plant at an 80% PRB /20% Illinois coal blend. The row in

Schedule TDF-ER8 with an 80% PRB / 20% Illinois coal blend has an average coal quality of 9,288 Btu/lb., which results in a unit capability of 428 net MW (pre-scrubber) or 419 net MW (post-scrubber).

Q. What was the coal quality for the Sioux plant during 2009, 2010 and the test year, and what is the plant's estimated rating based upon that coal quality?

A. The coal quality and estimated unit ratings for the periods are provided in the table below.

Period	PRB Coal Quality	ILL Coal Quality	Coal Blend %PRB/%ILL	Average Coal Quality	Rating based on coal Quality	Rating based on coal quality and Scrubber
2009	8830	11506	76.2% / 23.8%	9467	437	429
2010	8800	11114	78.2% /21.8%	9304	429	420
Test Year	8810	11200	80.0% / 20.0%	9288	428	419

Q. What values do you recommend for the Sioux ratings?

A. I recommend using 419 net MW based on the normal coal blend and normal coal quality, as reflected in the test year, adjusted for the impact of adding the scrubbers at Sioux. I would note that in my direct testimony I assumed that the net MW rating of each unit would decline by 12 MW due to the addition of the scrubbers. Based upon actual operations since the scrubbers went into service, the rating has only declined by 9 MW, a change that I have taken into account in my model results presented with this testimony.

Q. Why is Mr. Dauphinais' recommendation to change the Osage Plant's rating to 256 net MW incorrect?

A. Mr. Dauphinais based his rating for the Osage plant on a 2009 PROSYM "calibration run" that I provided for the purpose of validating the ability of the model to accurately simulate the Company's system. I have reviewed the Osage rating data used in my 2009 PROSYM calibration run and found that the value was incorrect. The Osage power plant never achieved 256 net MW during calendar year 2009. Instead, the highest plant generation level was 247 net MW and it reached this level for only 3 (out of 8,760) hours during the year. I have revised the 2009 calibration run rating to 237 net MW based on the fact that the plant output was equal to or lower than 237 net MW 95% of the hours in the year.

Q. Why shouldn't the 247 net MW level be used for the Osage Plant rating?

A. The 247 net MW output was achieved during high flow periods when the plant was operating under emergency conditions. During emergency conditions the plant is allowed (by its FERC license) to release more water, which in turn resulted in a higher than normal generation level. The 247 net MW level should not be used as a normalized plant rating, because it overstates the output that the generation the plant can be expected to achieve.

Q. What Osage rating do you recommend for use in the production cost model?

A. I recommend that the Osage rating used for determining normalized annual net fuel costs be set to the monthly unit rating listed in the Ameren Missouri Unit Capability Table Year 2011, which is an annual average of 237 net MW.

Q. Given the foregoing, should Mr. Dauphinais' adjustments relating to Sioux and Osage plant inputs be made?

A. No. The net fuel costs I have presented in this testimony accurately model the impact of the Sioux and Osage units on net fuel costs.

III. <u>STAFF REBUTTAL</u>

Q. Is there a problem with the Staff's calculation of the Sioux plant coal costs?

A. Yes, there is. The Staff used a coal blend based on the projected 2011 coal *delivery* blend (83% PRB / 17 % Illinois coal) rather than the *operating* blend of 80% PRB / 20% Illinois coal. I would also note that during the test year the *operating* blend was also 80%PRB / 20% Illinois coal. Since the Illinois coal is more expensive than PRB coal, the Sioux blended coal cost calculated by the Staff is understated by $.025/mmBtu.

Q. Did you discover problems with the Staff's calculation of normalized hourly power prices that are used in the production cost model to set normalized net fuel costs?

A. Yes, I did. The Company has discussed these problems with the Staff, and I believe they agree that they must be corrected. In fact, I recently received a response to Data Request UE-Staff-002, in which Staff witness Erin Maloney agreed to use the same prices that I have used in the Staff's production cost model. Specifically, Ms. Maloney agreed that: "for purposes of this case, . . . using DA [day-ahead] generation sales LMP prices would be the most appropriate prices to use to model generation dispatch and send the correct price signal in the REALTIME fuel model." Ms. Maloney also indicated that if these prices are used in the model the Staff believes some other adjustments need to be made outside the model. Ameren Missouri witness Jaime Haro addresses this "other adjustment" issue in his rebuttal testimony. Notwithstanding the Staff's apparent agreement regarding power prices, so that the record is clear, I will address the problems with Staff's method, as presented in their direct case filing, below.

Q. Please continue.

A. There are three major problems with the method that the Staff used as part of their direct case filing to calculate normalized power prices. The problems are: (1) the Staff improperly combined Day-Ahead Locational Marginal Prices ("DA-LMP") applicable to Ameren Missouri load and Day-Ahead Locational Marginal Prices applicable to Ameren Missouri Generation, (2) the Staff used a monthly average price based on *all* purchases and sales, which distorts the power price target used for normalizing power prices, and (3) the Staff used bilateral purchases and sales, which have LMPs that are different than those received at Ameren Missouri's generator nodes. Ameren Missouri witness Jaime Haro also discusses the third problem in his rebuttal testimony.

Q. What do you mean by a normalized hourly power prices?

A. Power prices have distinct patterns to them similar to customer load shapes. Schedule TDF-ER9 is a chart of actual power prices for the period May 1, 2010 through May 7, 2010 which illustrates this pattern.

Q. Why is an hourly price pattern important?

A. The hourly price pattern is important because it is used by the production cost model to calculate the revenues that can be earned from off-system sales when excess generation is available and it is used to determine if it is more economical to purchase power rather than operate generating units. Thus, if the hourly power prices are not developed using a reasonable method that accurately simulates what will happen in the real conditions of the market, the simulation will be wrong and will predict erroneous levels of off-system sales or power purchases. This will in turn inject inaccuracy into the rebasing of net base fuel costs in the case, which will then create larger FAC rate adjustments in the future.

Q. What is the problem with the way that the Staff combined the DA-LMP for Ameren Missouri's load and DA-LMP for Ameren Missouri's generating units?

A. As the name implies, the Locational Marginal Prices ("LMP") means that each location has a different price. Thus the LMP associated with Ameren Missouri's load is not representative of the LMP associated with Ameren Missouri's generating units, which are at another location. Since only the Ameren Missouri generating units are used to make spot off-system sales, it is not appropriate to use the Ameren Missouri load LMP to develop normalized power prices, which is what the Staff did when they combined the Ameren Missouri load LMPs and the Ameren Missouri generation LMPs. In the case of Ameren Missouri, the LMPs associated with the load are typically higher than the LMPs associated with the generation. For example, during the month May 2010 the average hourly Ameren Missouri load LMP was $29.08/MWh and the average hourly Ameren generator LMP was $28.01/MWh, which is a $1.07/MWh lower. Consequently, the Staff's method exaggerates normalized power prices. This will cause the model to generate an inaccurate level of fuel costs (higher fuel costs, because it will suggest Ameren Missouri will generate more MWhs), off-system sales (higher off-system sales revenues than can reasonably be expected), and purchased power (less than it should be). These inaccuracies lead to less accuracy in rebasing net fuel costs – in this case, it would lead to rebased net fuel costs that are too low, which creates a greater risk of larger fuel adjustment clause increases in the future.

Q. What is problem with the way that the Staff calculated its average monthly prices?

A. The Staff calculated the monthly average generator LMP by dividing the total generation revenues for the month by the total generation MWhs for the month. This approach produces a "high bias" for the monthly LMP because there is more generation during hours with higher LMPs and less generation during hours when the LMPs are lower. In other words, greater weighting was assigned to hours where the LMP was higher. A better method is to calculate a power price for each hour of the month and then average the hourly prices to determine the monthly average power price. An even more accurate approach is to separate the hourly LMPs into "on peak" and an "off peak" period averages for each month. This method applies the proper weighting to the LMPs.

Like the previous issue, the Company has discussed this issue with the Staff and the Staff has agreed to calculate the normalized hourly prices using hourly values which are grouped by "on-peak" and "off-peak" periods for each month.

Q. What are the problems associated with way the Staff handled bilateral sales in its direct case modeling?

A. There are two problems with the way that the bilateral sales were used. The first problem is that the Staff assumed that the bilateral sales price is representative of the price that could be obtained by Ameren Missouri's generating units. As previously discussed, all of the pricing is dependent on the location of the power sale and purchase. Consequently, it is incorrect to use the price of the bilateral sales to represent prices that the generator could achieve for its excess generation because the generating units are at a different location from where the bilateral sale transaction occurs. The proper valuation of bilateral sales is to net the revenue from the sale against the cost calculated using the LMP at the interface (location) where the bilateral sales occurred. The second problem with the Staff's modeling of bilateral sales is that many of them have fixed prices over consecutive hours, which distorts the hourly price shape (distortion of the hourly price shape means the wrong price is applied to the wrong hours). By way of further explanation, the use of fixed block sales prices will understate power prices during true high price periods and overstate prices during true low cost time periods. Therefore, bilateral sales must be excluded from the determination of normalized hourly power prices used in the production cost model.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers In the Company's Missouri Service Area.	)))))	Case No. ER-2011-0028

AFFIDAVIT OF TIMOTHY D. FINNELL

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Timothy D. Finnell, being first duly sworn on his oath, states:

1. My name is Timothy D. Finnell. I work in the City of St. Louis, Missouri, and I am employed by Ameren Services Company as a Managing Supervisor, Operations Analysis in Corporate Planning.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Union Electric Company d/b/a Ameren Missouri consisting of 11 pages, and Schedules TDF-ER7 through TDF-ER9, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Timothy D Finnell
Timothy D. Finnell

Subscribed and sworn to before me this 25 day of March, 2011.

Amanda Tesdall
Notary Public

My commission expires:

Amanda Tesdall - Notary Public
Notary Seal, State of
Missouri - St. Louis County
Commission #07158967
My Commission Expires 7/29/2011

NES 08-0019

December 1, 2008

Randall Irwin
Gary Blessing
Lee Eitel
James Warner
Dan Trokey
Tim Finnell
Tom Antweiler
Jeff Shelton
Regional Regulatory Affairs Supervisor
A160.0924

2009 Callaway Plant Capability Report

The Main 2009 capabilities are based on the MAIN (Mid-America Interconnected Network) Guide definition of monthly capability. Per the guide, net capability is corrected each month to account for changes in ambient temperature. The correction is based on an average of the warmest circulating water temperature each day averaged over a month (for 5 years). These capabilities represent what Callaway should be able to achieve during the four warmest hours of the day on an average temperature day. They are not intended to represent the worst possible peak load.

The Average 2009 capabilities are based on an average circulating water temperature each month. These capabilities represent what Callaway should be able to average for an entire month.

Due to the removal of the mechanical excitation system in refuel 15, gross capability increased by 2 MWe. An electrical excitation system was added at that time which increased house loads by 2 MWe. Therefore, net capability remained unchanged. The table below reflects this change. There are no generation uprates scheduled in 2009.

Please contact me at extension 68366 for any further information.

	Main	2009	Average	2009
	Gross	Net	Gross	Net
Month	Capability	Capability	Capability	Capability
January	1298	1240	1301	1243
February	1294	1236	1298	1240
March	1291	1233	1296	1238
April	1288	1230	1291	1233
May	1268	1210	1274	1216
June	1255	1197	1265	1207
July	1248	1190	1255	1197
August	1252	1194	1257	1199
September	1264	1206	1271	1213
October	1288	1230	1283	1225
November	1294	1236	1295	1237
December	1297	1239	1300	1242
Average	1278	1220	1282	1224

Brian A Pae

Brian A. Pae
Thermal Performance Engineer

NES 09-0017

December 7, 2009

Randall Irwin
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2010 Callaway Plant Capability Report

The Main 2010 capabilities are based on the MAIN (Mid-America Interconnected Network) Guide definition of monthly capability. Per the guide, net capability is corrected each month to account for changes in ambient temperature. The correction is based on an average of the warmest circulating water temperature each day averaged over a month (for 5 years). These capabilities represent what Callaway should be able to achieve during the four warmest hours of the day on an average temperature day. They are not intended to represent the worst possible peak load.

The Average 2010 capabilities are based on an average circulating water temperature each month. These capabilities represent what Callaway should be able to average for an entire month.

There are no changes in the 2010 capability report when compared to the 2009 capability report issued December 1, 2009. There are no generation uprates scheduled in 2010.

Please contact me at extension 68366 for any further information.

	Main	2010	Average	2010
	Gross	Net	Gross	Net
Month	Capability	Capability	Capability	Capability
January	1298	1240	1301	1243
February	1294	1236	1298	1240
March	1291	1233	1296	1238
April	1288	1230	1291	1233
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Brian A. Pae
Thermal Performance Engineer

NES 10-0014

August 24, 2010

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A160.0924

2011 Callaway Plant Capability Report

The Main 2011 capabilities are based on the MAIN (Mid-America Interconnected Network) Guide definition of monthly capability. Per the guide, capability is corrected each month to account for changes in ambient temperature. The correction is based on an average of the warmest circulating water temperature each day averaged over a month (for 5 years). These capabilities represent what Callaway should be able to achieve during the four warmest hours of the day on an average temperature day. They are not intended to represent the worst possible peak load.

The Average 2011 capabilities are based on an average circulating water temperature each month. These capabilities represent what Callaway should be able to average for an entire month.

There are no changes in the 2011 capability report when compared to the 2010 capability report issued December 7, 2009. There are no generation uprates scheduled in 2011.

	Main	2011	Average	2011
	Gross	Net	Gross	Net
Month	Capability	Capability	Capability	Capability
January	1298	1240	1301	1243
February	1294	1236	1298	1240
March	1291	1233	1296	1238
April	1288	1230	1291	1233
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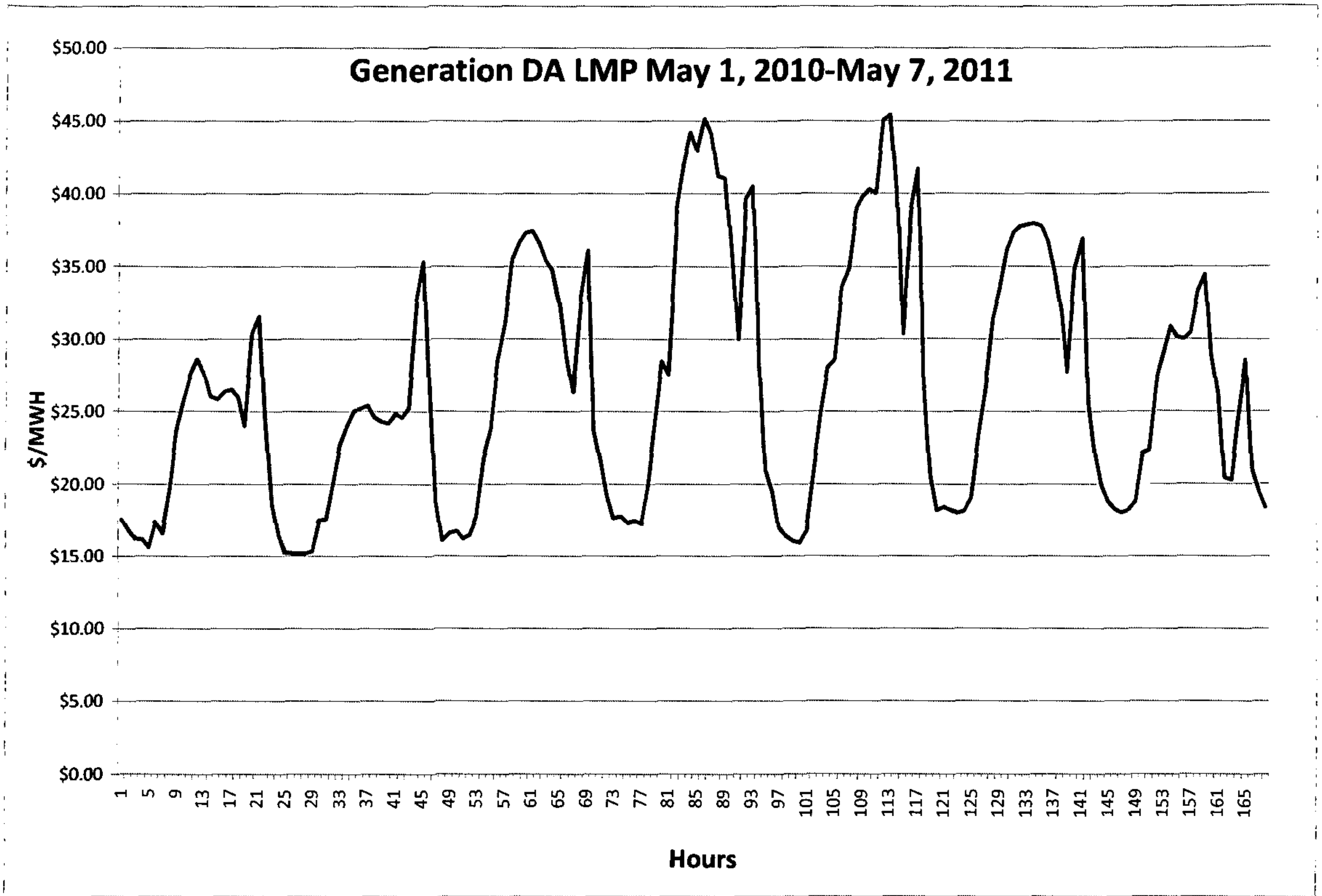
Average	1278	1220	1282	1224

B A Pae

Brian A. Pae
Thermal Performance Engineer

SIOUX PLANT
SO2 and Predicted Loads for Fuel Blends

	PRB	8810	Net Load	Net Load
	ILL	11200	95% Fuel	95% Fuel
Actual BLEND % PRB	Actual BLEND % Ill	BTU/LB	No Scubber	With Scrubber
100%	**0%**	8810	402	394
95%	**5%**	8930	409	400
90%	**10%**	9049	415	407
85%	**15%**	9169	421	413
80%	**20%**	9288	428	419
75%	**25%**	9408	434	426
70%	**30%**	9527	441	432
65%	**35%**	9647	447	439
60%	**40%**	9766	454	445
55%	**45%**	9886	460	451
50%	**50%**	10005	466	458
45%	**55%**	10125	473	464
40%	**60%**	10244	479	471
35%	**65%**	10364	486	477
30%	**70%**	10483	492	484
25%	**75%**	10603	499	490
20%	**80%**	10722	505	497
15%	**85%**	10842	509	500
10%	**90%**	10961	509	500
5%	**95%**	11081	509	500
0%	**100%**	11200	509	500



Schedule TDF-ER9