Exhibit No.:	
Issues:	AmerenUE Capacity; Cost Analyses
Witness:	Richard A. Voytas
Sponsoring Party:	Union Electric Company d/b/a AmerenUE
Type of Exhibit:	Direct Testimony
Case No.:	EA-2005-0180
Date Testimony Prepared:	December 20, 2004

MISSOURI PUBLIC SERVICE COMMISSION

Case No. EA-2005-0180

DIRECT TESTIMONY

OF

RICHARD A. VOYTAS

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

**** Denotes Highly Confidential Information****

St. Louis, Missouri
December, 2004

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**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**

Application of Union Electric Company for a Certificate of Public Convenience and Necessity authorizing it to construct, install, own, operate, control, manage and maintain electric plant, as defined in § 386.020(14), RSMo. to provide electric service in a portion of New Madrid, County, Missouri, as an extension of its existing certificated area	))))))))	Case No. EA-2005-0180

AFFIDAVIT OF RICHARD A. VOYTAS

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

Richard A. Voytas, being first duly sworn on his oath, states:

1. My name is Richard A. Voytas. I work in St. Louis, Missouri, and I am employed by Ameren Services Company as Manager of the Corporate Analysis section in the Corporate Planning Department.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company d/b/a AmerenUE consisting of 26 pages, Appendices A and B, and Schedules RAV-1 through RAV-13, 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.

Richard A. Voytas
Richard A. Voytas

Subscribed and sworn to before me this 20th day of December, 2004.

Mary Hoyt
Notary Public

My commission expires: 4-1-2006

MARY HOYT
Notary Public - Notary Seal
STATE OF MISSOURI
Jefferson County
My Commission Expires: April 1, 2006

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DIRECT TESTIMONY

OF

RICHARD A. VOYTAS

UNION ELECTRIC COMPANY

d/b/a AmerenUE

CASE NO. EA-2005-0180

I. <u>Introduction.</u>

Q. Please state your name and business address.

A. My name is Richard A. Voytas. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

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

A. I am employed by Ameren Services Company as Manager of the Corporate Analysis section in the Corporate Planning Department. The Corporate Planning Department provides various corporate, administrative and technical support services for Ameren Corporation ("Ameren") and its affiliates, including Union Electric Company d/b/a AmerenUE (referred to herein as "Company" or "AmerenUE").

Q. How long have you held your position, and what are your responsibilities?

A. The attached Appendix A summarizes my educational background, work experience and the duties of my position.

Q. How is your testimony organized?

A. Section II describes and discusses Noranda Aluminum, Inc. ("Noranda"), and the load to be served as proposed in the Company's Application. Section III discusses the Company's generating capacity position. Section IV explains the basic modeling assumptions used in the analyses presented with my testimony. Section V contains a discussion of those analyses that address the effect of adding the Noranda load on the per megawatt hour ("MWh") costs for AmerenUE on both a "total system" or "total AmerenUE" basis, and also strictly from the perspective of the effect on per MWh costs for AmerenUE's native load customers (i.e. AmerenUE's ratepayers).[1] Section VI discusses certain sensitivities that were performed on the base analyses. Finally, Section VII summarizes my testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with information about AmerenUE's capacity position relative to serving the Noranda load, and to provide the Commission with the results of analyses that address the effect of adding the Noranda load on AmerenUE's costs per MWh over a twenty year planning horizon relative to not adding the Noranda load.

II. <u>Noranda and Noranda's Load.</u>

Q. Please describe Noranda, its load, and its need for electricity.

A. Noranda owns a large (annual production capacity of approximately 250,000 metric tons) aluminum smelter situated just outside New Madrid, Missouri in New Madrid County, Missouri. Noranda is the largest electric energy user in Missouri with a consumption of approximately 4.1 million MWh's of electricity per year, a peak demand of 470 megawatts ("MW"), and an annual load factor of 98%. Reliable, low cost energy is critical to Noranda, representing its number one cost of operation. Reliable, low cost energy is also therefore critical to Noranda's continued ability to contribute to the

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1 When I refer to "native load" customers, I am referring to AmerenUE Missouri retail load.

economy of Missouri, including Southeast Missouri in the form of, among other things, Noranda's employment of 1,100 and the tax revenues it and its employees provide.

Q. What is the significance of Noranda's annual load factor?

A. An electricity customer's load factor is a measure of how many hours of the year the customer consumes the maximum energy it might need. As noted earlier, this means that Noranda consumes its maximum electricity needs 98% of the hours in a year. That means that Noranda is constantly using electricity and as I understand it, the nature of aluminum smelting operations means that Noranda cannot ramp-up or ramp-down production but must in effect produce at full output all of the time. This also means that Noranda uses a lot of power during off-peak times, and as discussed further below, AmerenUE, as a utility with a large proportion of baseload generation, has available energy during these off-peak times that can be effectively and indeed more efficiently sold to a high load factor customer like Noranda. I would note that in comparative terms, the Metro East load which AmerenUE must shed in order to have the capacity to serve Noranda, has a lower load factor (79%), and on a system-wide basis, AmerenUE has a load factor of approximately 53%. Noranda's comparatively higher load factor therefore provides AmerenUE opportunities to sell off-peak energy that it has available, some of which it previously could not sell.

Q. Is the Noranda plant currently located in the AmerenUE service territory?

A. No.

Q. What is the date that Noranda anticipates it will obtain 100% of its electric capacity and energy requirements from AmerenUE?

A. AmerenUE and Noranda have entered into an Agreement (attached as Schedule CDN-1 to Mr. Craig D. Nelson's pre-filed direct testimony) under which AmerenUE would begin to supply Noranda's electric energy requirements effective June 1, 2005, subject to certain conditions. AmerenUE would begin serving Noranda on that date because its current electric supply arrangements end on May 31, 2005, and will not be renewed.

III. AmerenUE's Capacity Position.

Q. You mentioned that the commencement of AmerenUE's service to Noranda on June 1, 2005 is subject to certain conditions. Please describe those conditions.

A. The conditions relate to steps that must be completed in order for AmerenUE to have sufficient capacity to serve Noranda. The first condition is that the Metro East service area be transferred to AmerenCIPS by June 1, 2005. Completion of the Metro East transfer in effect makes 597 MW of capacity available to AmerenUE because AmerenUE will shed the Metro East load. AmerenUE's ability to serve Noranda is also dependent upon AmerenUE's purchase of the Kinmundy and Pinckneyville combustion turbine generators ("CTGs") from Ameren Energy Generating Company. Those CTGs will add approximately 552 MW of capacity for AmerenUE. Thus, the second condition is transfer of those CTGs to AmerenUE by June 1, 2005. AmerenUE needs to complete both transactions by June 1, 2005 in order to have sufficient capacity to serve all of AmerenUE's native load requirements including the Noranda load while maintaining a minimum, short-term 15% planning reserve margin beginning in 2005.

Q. If AmerenUE was not going to serve Noranda, what would be AmerenUE's capacity position in 2005 if those two conditions, namely completion of the transfer of the

Kinmundy/Pinckneyville CTGs and completion of the Metro East transfer were not completed?

A. Without both of those transfers, AmerenUE is ** ** short of its short-term 15% planning reserve margin and ** ** short of its long-term 17% planning reserve margin in 2005. *See* Schedule RAV-1 attached hereto and incorporated herein.

Q. Even though AmerenUE will not consider this option, for illustrative purposes to show the magnitude of AmerenUE's potential capacity needs, assume AmerenUE were to serve the Noranda load but that the acquisition of the Kinmundy/Pinckneyville CTGs and the Metro East transfer does not occur. Under those assumptions, what would AmerenUE's capacity position be in 2005?

A. The Noranda load is approximately 470 MW.[2] To determine the capacity associated with the Noranda load, we must add 15% and 17% respectively to cover the associated short-term and long-term planning reserve margins. Thus, the capacity required to serve Noranda is 541 MW at AmerenUE's short-term 15% planning reserve margin and 550 MW at AmerenUE's long-term 17% planning reserve margin. If Noranda were added, but if the CTG acquisitions and Metro East transfers were not completed, AmerenUE would be ** ** short of a 15% planning reserve margin and ** ** short of a 17% planning reserve margin in 2005. *See* Schedule RAV-2 attached hereto and incorporated herein.

Q. Can AmerenUE add between ** ** of additional capacity, whether peaking or baseload capacity, by June 1, 2005?

[2] The capacity figures used herein are based on a Noranda load of 470 MW. Noranda needs slightly more capacity (approximately 17 MWs) to cover the energy line losses that AmerenUE will also provide (at Noranda's cost, as discussed in Mr. Wilbon Cooper's pre-filed direct testimony). Those 17 MWs have no material impact on the

A. No. AmerenUE needs, at a minimum, 12 to 18 months lead time to construct new peaking plants and several years lead time to construct new baseload generation. AmerenUE would consider the option of acquiring existing peaking plants that are located within the Ameren control area, but there is virtually no chance that AmerenUE could acquire **____________** of peaking capacity with no transmission service limitations within the Ameren control area.

Q. Assume that both AmerenUE's acquisition of the Kinmundy/Pinckneyville CTGs and the Metro East transfer are completed prior to June 2005 and AmerenUE does not serve the Noranda load. What is AmerenUE's capacity position in that scenario?

A. AmerenUE's capacity position in that scenario is shown on Schedule RAV-3 attached hereto and incorporated herein. Under that scenario, AmerenUE expects to have **____________** of capacity in excess of a 15% planning reserve margin in 2005, to have **____________** of capacity in excess of a 15% planning reserve margin in 2006, and to be **____________** short of a 15% planning reserve margin in 2007, and to be short every year thereafter absent capacity resource additions to be identified in the AmerenUE twenty year resource plan. For the same years relative to a 17% planning reserve margin, AmerenUE expects to exceed the 17% margin by **___________** in 2005, and to be short of the 17% margin by **_________** in 2006, by **__________** in 2007, and to be short every year thereafter absent capacity resource additions identified in the AmerenUE twenty year resource plan.

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analyses discussed herein or on AmerenUE's overall capacity position.

**Q.

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Q. Now assume that both AmerenUE's acquisition of the Kinmundy/Pinckneyville CTGs and the Metro East transfer are completed prior to June 2005 and that AmerenUE <u>serves</u> the Noranda load beginning June 2005. What is AmerenUE's capacity position?

A. This is the scenario that will exist if AmerenUE's Application in this case is granted, assuming that the other necessary transfers occur and AmerenUE is able to serve Noranda. In this scenario, relative to a 15% planning reserve margin, AmerenUE expects to be slightly short ** ** on capacity in 2005, ** ** short on capacity in 2006, ** ** short on capacity in 2007, and short every year thereafter absent capacity resource additions to be identified in the AmerenUE twenty year resource plan. *See* Schedule RAV-4 attached hereto and incorporated herein. For the same years relative to a long-term 17% planning reserve margin, AmerenUE expects to be ** ** short on capacity in 2005, ** ** short in 2006, ** ** short in 2007, and short every year thereafter absent capacity resource additions identified in the AmerenUE twenty year resource plan.

**Q.

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IV. <u>Modeling Assumptions.</u>

Q. In the Introduction section of your testimony, you referred to analyses that were conducted. In simple terms, how were those analyses done?

A. The analyses were conducted using the Multiobjective Integrated Decision Analysis System ("MIDAS") production costing model. The MIDAS production costing model is an economic dispatch model. Using the MIDAS model, AmerenUE generation units were economically dispatched hour by hour to meet the AmerenUE load. When market power prices were less than the incremental cost of production from AmerenUE units, the AmerenUE generation units were backed down and power was purchased from the market. Likewise, when AmerenUE generation units had capacity above that needed to serve AmerenUE load and that power cost less than market power prices, the excess power was sold to the market subject to transmission export limitations and market depth limitations. This process was done once for the AmerenUE system with no Noranda load (the "without Noranda" case) and repeated a second time with the Noranda load (the "with Noranda" case). Annual average production costs in terms of $/MWh were calculated for both cases.

Q. List the principal assumptions that support the production cost simulations performed by the MIDAS model.

A. Assumptions common to all scenarios included: (1) Kinmunday and Pinckneyville CTGs transfer to AmerenUE by the end of 2004; (2) Metro East load transfers to AmerenCIPS by the end of 2004; (3) Install two 501F CTGs at Venice in June 2005; (4) Build CTGs in the following ratios: 25% aero-derivative, 25% small frame, 50% large frame; (5) AmerenUE embedded costs were held constant at 2003 levels; 6) AmerenUE operates as a stand-alone system (i.e., as if there was no Joint Dispatch Agreement); and (7) the capacity charge is based on a 14.45% annual carrying charge rate.

Assumptions for the two “with Noranda” scenarios included: (1) Noranda becomes an Ameren UE customer on June 1, 2005; (2) Noranda adds 470 MW of load plus 15% reserve (540 MW total) on June 1, 2005; (3) Noranda’s load factor is 98%; (4) Noranda remains an AmerenUE customer for the duration of the study (20 years); (5) 600 MW unspecified peaking capacity is acquired in 2006-7 for $283 million ($471/KW).

Q. One of the assumptions common to all scenarios was that embedded costs were held constant. Please explain why those costs were held constant?

A. The purpose of the analyses was to estimate both the magnitude and direction of the cost impact on AmerenUE of adding the Noranda load. The purpose was not to estimate AmerenUE’s future embedded costs for every year of the analysis. Consequently, embedded costs that are common to AmerenUE under both the with Noranda and without Noranda cases do not impact the analysis.

Q. What about additional capital costs associated with the need for AmerenUE to acquire 600 MW of additional peaking capacity to serve Noranda? How are these costs factored into the analysis?

A. These costs are included in the "New Capacity Charge" line in Schedules RAV-6 and RAV-7 attached hereto and incorporated herein. Schedules RAV-6 and RAV-7 show the results of the two analyses, as discussed in more detail below. Initially, AmerenUE modeled only the 600 MW of additional peaking capacity required to serve the Noranda load. The reason for this is that once AmerenUE builds or acquires a 600 MW block of CTGs for the Noranda load, any subsequent capacity additions over the remainder of the twenty year analysis horizon will be the same under both the with and without Noranda cases. Therefore, the costs associated with that additional capacity are common to both cases.

Q. Did AmerenUE revise its methodology for including native load capacity costs in its analyses?

A. Yes. During meetings with the Commission's Staff and others which focused on AmerenUE's workpapers used in the analyses, Dr. Michael S. Proctor, the Commission's Chief Regulatory Economist in the Energy Department, noted that while the same capacity was being added for both the with Noranda and without Noranda cases, the timing of AmerenUE's expansion plans was somewhat different between the two cases. The timing of an expansion plan may impact an analysis because capacity additions that are added sooner should increase the embedded cost calculation. We agreed to make changes in the calculation of native load capacity costs to reflect the differences in timing of the capacity addition plans under both the with Noranda and without Noranda cases.

Q. How are capacity costs converted into annual costs which are then converted into $/MWh costs in the analyses?

A. Capacity costs are multiplied by AmerenUE's levelized annual fixed charge rate in order to calculate the annual carrying costs associated with owning an asset. Then the annual cost is divided by native load (in the Native Load Approach) sales and by native load plus off-system sales (in the Total System Approach) to convert the annual cost to $/MWh.

Q. Explain the term "fixed charge rate".

A. As used in these analyses, a fixed charge rate is the average annual carrying cost to finance a capital project like the construction or purchase of a CTG. It is based on AmerenUE's marginal capital structure.

Q. What is the debt/equity ratio and the debt rate and equity rate used in the calculation of the 14.45% annualized fixed charge rate associated with building new CTGs?

A. The debt/equity ratio is 45/55. The debt rate is 8%. The equity rate is 13%.

Q. What scenarios were modeled for each of the two cases (with and without Noranda)?

A. Four scenarios were modeled:

1. Do not acquire Noranda, and build a coal unit and a mix of CTGs.
2. Do not acquire Noranda, and build only a mix of CTGs.
3. Acquire Noranda, and build/acquire a CTG plant for Noranda in 2006, and build a coal unit and a mix of CTGs.

4. Acquire Noranda, and build/acquire a CTG plant for Noranda in 2006, and build a mix of CTGs.

Q. Why were these scenarios chosen?

A. The most recent resource plans submitted to Staff and Public Counsel in the Company's biennial resource planning briefings indicate that the two most likely (least cost) expansion plan options for AmerenUE over the next twenty years are (1) build one coal unit and use CTGs for the balance of AmerenUE's future capacity needs; and (2) build all CTGs. To evaluate the impact of acquiring Noranda as a customer, we modeled scenarios with and without Noranda.

Q. Previously in your testimony you stated that AmerenUE will need to add approximately 600 MW of peaking <u>capacity</u> in 2006 to meet the incremental capacity needs of the Noranda load. Does AmerenUE have sufficient <u>energy</u> from its existing generation fleet to cover the incremental energy needs of Noranda?

A. Yes. Attached to my testimony as Schedule RAV-8 is a graphical display of the forecast of AmerenUE's 2008 load duration curve with and without the Noranda load. The load duration curve shows that for approximately 85% of the hours of the year AmerenUE has sufficient baseload energy plus reserves to meet existing AmerenUE native load and the Noranda load. For those hours where AmerenUE load exceeds its baseload capacity, AmerenUE will serve native load including the Noranda load with AmerenUE's mix of peaking and intermediate capacity resources.

Q. Does the potential addition of the Noranda load change either the timing of AmerenUE's future capacity needs or the type (i.e., peaking, intermediate, baseload) of capacity that is the least cost resource?

A. No. AmerenUE conducts asset mix optimization or least cost resource planning studies on a continual basis. Prior studies which included AmerenUE's Metro East load showed a need for a mix of CTGs and one baseload plant as the least cost resource mix for AmerenUE's twenty-year resource plan. If the 98% load factor 470 MW Noranda load is substituted for the approximately 79% load factor 510 MW Metro East load, the least cost mix of resources will not change. In fact, due to the need for increased energy requirements to serve the Noranda load, the expectation is that the economics of adding a baseload plant will improve.

Q. What is the expected timing for the addition of a future baseload plant at AmerenUE?

A. Prior least cost resource planning studies have shown that a baseload plant should be added in the 2011-2013 timeframe.

Q. Does the addition of the Noranda load change the in-service date for a new baseload plant at AmerenUE?

A. No. The addition of the Noranda load will not accelerate or delay the timing for a new baseload plant.

V. <u>Annual Average Cost Analyses.</u>

Q. You mentioned earlier that analyses were performed relating to the effect of adding the Noranda load on AmerenUE's $/MWh costs. What were the analyses designed to show and what were the analyses not designed to show?

A. As with any potential future load, adding significant load like Noranda requires that the Company engage in a resource planning process to evaluate various options. Resource planning analyses of this type indicate which of two or more options is likely to result in either higher or lower costs relative to the other options under consideration. For example, resource planning analyses may examine whether the costs to build a coal-fired plant will be lower or higher than building a gas-fired combustion turbine or, as here, whether adding the Noranda load versus not adding the Noranda load will result in higher or lower costs. In short, resource planning of this type is designed to determine which of the options under consideration is the least cost option. Resource planning analyses do not, however, indicate the effect of choosing one option or another on future customer rates.

Q. If you always choose the least cost option under consideration, wouldn't customer rates always go down?

A. No. Rates may go in either direction because there are innumerable cost and expense factors that bear upon rate levels. In some cases, all potential options under consideration may tend to increase rates, but one option versus another (the least cost option under consideration) would be the one that minimizes the extent of any proposed rate increases. In short, the analyses presented in this testimony do not bear upon the question of what are the appropriate rate levels irrespective of whether or not Noranda is a customer or AmerenUE. Customer rates are determined by the Commission based on comprehensive cost of service studies done to allocate the Company's total costs among rate classes based on the Company's allowed revenue requirement.

Q. Please provide an overview of the analyses that were done to determine if the addition of the Noranda load increases or decreases annual average AmerenUE costs on a $/MWh basis.

A. The analyses performed examined the $/MWh costs for AmerenUE for two options -- adding the Noranda load or not adding the Noranda load. Two similar analyses, examining those costs from different perspectives and examining each of the four scenarios identified earlier in my testimony, were performed. As a result of a series of recent meetings and consultations with the Commission's Staff, the Office of Public Counsel, representatives of some of the Company's large industrial customers, and the Missouri Department of Natural Resources, it was determined that analyzing the cost of adding the Noranda load from the perspective of the effect on average costs for AmerenUE's native load customers (i.e. its ratepayers) was the most relevant analysis (I sometimes refer to this approach herein as the "Native Load Approach"). Analyzing the costs from that perspective (as opposed to a "total system" perspective, as discussed further below), was suggested by Dr. Proctor. In summary, the Native Load Approach suggested by Dr. Proctor first analyzes the Company's costs per MWh by spreading those costs over only the MWh sales to native load customers (rather than spreading those costs over the MWh sales of both native load customers and off-system sales of power to buyers of power from AmerenUE in the open market). After spreading those costs over native load sales only, a second step in the Native Load Approach is to account for any lost off-system sales margins (profits) that may occur since Noranda will consume some (but as the analysis shows, not nearly all) of the power that without Noranda might have been sold off-system. After those two steps are completed, the overall effect on AmerenUE's $/MWh costs can be seen from the perspective of native load customers. The results of this approach as presented by Dr. Proctor and accepted by AmerenUE for the purposes of this filing are attached hereto and incorporated herein as Appendix B.

Q. Please describe the second analysis.

A. The second analysis, performed prior to the above-noted meetings, examined the costs per MWh from the "total system" perspective (I sometimes call this approach the "Total System Approach"), meaning that the Company's costs were spread over all MWh sales by the Company, both to native load customers and to off-system buyers of power.

Q. In describing the two analyses, you referenced AmerenUE's costs. Are the costs used in both analyses the same?

A. Yes. Both analyses take all of AmerenUE's costs into account, including production costs, embedded costs, and costs associated with adding new capacity over the 20-year period of the analyses. Those costs are then divided by the MWh sales (native load sales only, in the Native Load Approach, and native load sales plus off-system sales, in the Total System Approach) to arrive at a cost per MWh. Each analysis examines the cost per MWh with and without Noranda, and the difference in costs per MWh between the with and without Noranda cases gives us the cost per MWh effect of adding Noranda.

Q. Please provide more detail on the components of the costs examined.

A. The main categories of costs are as follows:

1. Native load production costs
2. Native load embedded costs
3. Native load capacity costs for added capacity
4. Margin (Profits) from off-system sales

Q. What makes up the first item, native load production costs?

A. The native load production costs consist of the following components:

- Total production costs

- + Fuel
- + Variable O&M
- + Fixed O&M

- Emissions Costs
  - + SO_2
  - + NO_x
- Off-system Sales/Purchases
  - + Purchased power costs
  - – Off-system sales production costs
  - –Emissions costs for off-system sales

Q. What makes up the second item, native load embedded costs?

A. Native load embedded costs are all costs other than production costs. Components are:

- Return on rate base
- Production operating expenses – other
- Transmission operating expenses
- Distribution operating expenses
- Customer accounts operating expenses
- Customer Service & Info operating expenses
- Sales operating expenses
- A&G Operating expenses
- Depreciation expense
- Taxes other than income
- Income taxes at allowed return

- Deferred investment tax credit – net
- Deferred income taxes

Q. What makes up the third item, native load capacity costs?

A. Native load capacity costs are for future capacity additions needed to meet both existing AmerenUE Missouri retail load growth and the Noranda load for the entire twenty year planning horizon. The generation technologies included over the twenty year planning horizon are one large baseload unit in the 2011-2013 period with several CTGs during other periods. Those generation technologies and the timing of each are consistent with AmerenUE's most recent resource plans, but as noted earlier, adding Noranda will cause AmerenUE to add a 600 MW block of CTGs in 2006 to cover the one-time load increase attributable to Noranda.

The components of estimated native load capacity costs used in this analysis are:

- $471/kW for 600 MW of CTGs required to serve the Noranda load
- $1800/kW for any baseload plant to be added per the existing resource plan
- $520/kW for any aero-derivative CTGs to be added per the existing resource plan
- $440/kW for any small frame CTGs to be added per the existing resource plan
- $410/kW for any large frame CTGs to be added per the existing resource plan

Q. For the Native Load Approach, what did the actual model results show in terms of how the addition of the Noranda load impacts AmerenUE's annual average $/MWh cost?

A. The modeling results showed that for every year of the analysis the addition of the Noranda load lowered AmerenUE's native load production costs in the range of $2 to

$3/MWh. Results of the analysis are shown in Schedule RAV-6 attached hereto and incorporated herein.

Q. Please describe the results shown in the table in the lower left-hand corner of Schedule RAV-6.

A. That table reflects the $2 to $3/MWh cost savings from adding Noranda and examines the savings for each of the four scenarios analyzed and described earlier in my testimony. Scenarios 3 and 1 were paired and the results of the with and without Noranda cases were compared, as were scenarios 4 and 2. As the table shows, the average cost savings on a $/MWh basis from adding Noranda were greatest over the 20 year study period if AmerenUE sticks with its preferred resource plan, that is, to build a coal-fired baseload plant plus additional CTGs as needed (scenario 3 less scenario 1).

Q. Before Dr. Proctor's suggestion that the addition of Noranda be analyzed from the native load customer's perspective you indicated you performed a Total System Approach analysis. Please discuss the Total System Approach in more detail.

A. Whenever AmerenUE conducts integrated resource planning analyses (such as the resource plans required by Commission regulations), AmerenUE models the total system rather than just focusing on native load. We therefore initially took that same approach regarding Noranda, though by definition the Native Load Approach provides a more focused and perhaps more accurate view of the impact on native load costs in terms of $/MWh.

Q. Does the Total System Approach also give an indication of how the addition of the Noranda load impacts annual average costs?

A. Yes. The Total System Approach will give an indication of whether the addition of the Noranda load has a positive or negative impact on the annual average total system $/MWh costs, but it doesn't focus solely on native load customers.

Q. What were the results of the Total System Approach analysis?

A. The results show that the addition of the Noranda load lowers total system annual average costs by $0.46/MWh over the twenty year study period. Results of the analysis are shown in Schedule RAV-7. Schedule RAV-7 contains the same table as appears in Schedule RAV-6 showing the difference in costs from a total system perspective, with and without Noranda, using the same four scenarios discussed above.

Q. Regardless of whether you examine annual average costs using the Native Load Approach or the Total System Approach, is an annual average cost analysis an accepted methodology in Missouri for considering the economic impact of adding a load such as Noranda?

A. Yes. When examining load-building programs, the Commission's regulations require "a comparison of annual average rates in each year of the planning horizon for the resource plan with and without the load building program." See 4 CSR 240-22.060(5)(B). Adding the Noranda load is in substance load-building. In this case, the new load happens to be approximately 470 MW.

Q. Both the Native Load and Total System Approaches show that serving Noranda lowers annual average costs on a $/MWh basis, but they yield different levels of cost reductions. At a high-level, please describe in more detail the differences between the two calculations.

A. The total system calculation is average cost for AmerenUE in total. The native load calculation is average cost for AmerenUE native customers or ratepayers.

Mathematically, both of the average costs calculations (avg. cost = cost /load) use the same set of costs, and those same costs are outlined earlier in my testimony. The methods differ in the load that is used in the denominator. The total system calculation uses the sum of native load and off-system sales (avg cost = cost /[native load + off-system sales]). In contrast, the native load calculation only uses native load in the denominator (avg cost = cost /native load).

Conceptually, the differences in the calculations yield an average cost from two different perspectives. The total system calculation averages all the costs over *all* MWhs sold by AmerenUE. The denominator is larger, thus the average costs per MWh will be lower, all else being equal. The native load calculation averages all the costs over *only* the MWhs sold to AmerenUE native load -- ratepayers. With the native load average costs, the costs are spread over fewer MWhs, thus the average costs will be higher.

Q. The above discussion focuses on the absolute level of costs. Is that the relevant consideration?

A. No. The relevant consideration is the *difference* between the with and without Noranda cases, *not* the absolute level of average costs under the Total System Approach versus the Native Load Approach. In other words, when we analyze the “without Noranda” case under the Total System Approach, we get a lower absolute level of average costs per MWh than under the Native Load Approach. However, when we compare the with and without Noranda cases, the difference – the cost savings -- is greater from the Native Load Approach perspective as discussed above because, principally, serving a higher load factor customer helps utilize available off-peak energy that could not otherwise be profitably sold off-system and also helps spread fixed costs over more MWhs.

I illustrate the mathematics of the two approaches in Schedule RAV-9 using 2008 costs as an example. The absolute level of costs with and without Noranda under the Native Load Approach is higher ($64.81 and 61.82 per MWh, respectively) than under the Total System Approach ($55.46 and $55.12, respectively), but clearly from the native load perspective adding Noranda shows greater overall cost savings ($2.99 versus $0.34 per MWh in 2008).

Q. Please summarize the basics of why adding load, in this case the Noranda load, lowers AmerenUE's average annual $/MWh costs?

A. There are two basic factors that underlie the decrease in the $/MWh cost. I alluded to the first factor earlier, that is, the impact of Noranda being an almost 100% load factor customer. This means that Noranda takes as much energy off-peak as it does on-peak. Off-peak generation costs are less than on-peak generation costs so selling this off-peak power to Noranda, some of which simply could not be sold off-system at all, generates margins for AmerenUE (and for its customers in the form of a lowered revenue requirement) that would not exist without Noranda. Thus, AmerenUE's overall native load variable production costs decrease on a $/MWh basis. The second factor concerns the embedded cost calculation. The addition of the almost 100% load factor Noranda load means that there are more MWh sales over which to spread embedded or fixed costs thereby decreasing the embedded costs on a $/MWh basis.

VI. <u>Sensitivities To Base Case Analyses.</u>

Q. You earlier discussed a series of meetings and other consultations with Staff, Public Counsel, and others during which the various analyses were discussed. Have you made some adjustments to your initial analyses based on those meetings and consultations?

A. Yes. In addition to conducting the analysis using the Native Load Approach suggested by Dr. Proctor, we have examined some other "sensitivities" to the results of the analyses presented in my testimony, and in particular, have examined sensitivities to the results shown in Schedules RAV-6 and RAV-7.

Q. Please explain.

A. In order to perform any analysis, input variables must be developed and then used throughout the entire analysis to assure study consistency (i.e. analysts should not use data for one variable from one time period and for other variables from another time period as this leads to inconsistency and "apples and oranges" results). In the Noranda analysis, we used a mid-May 2004 date to establish the prices for a number of variables including SO2 allowances, NOx allowances, natural gas prices, and the off-system power prices (mid-May prices were used because they were the prices available to us when the modeling process was begun in May-June 2004). In our view, use of data from just a few months ago is appropriate given prices for these kinds of variables will without question go up and down numerous times over the 20 year horizon of the analyses. If the prices go up and down over that 20 year period, the price level changes will be common to both the with and without Noranda cases and thus will not affect the analysis.

Q. Have you performed any sensitivity analysis on the variables you just mentioned?

A. Yes. Because we were asked to do these sensitivities and because the data was readily available, we have taken price level changes since May 2004 into account in the sensitivities discussed below. As I mentioned earlier, however, prices could change again next week, next month, next year, or 10 years from now, but the changes would be common to both cases.

Q. Please describe the sensitivity analysis performed and the impact on the results of the Noranda analysis.

A. The sensitivity analysis which was performed was to take the results from the Noranda analysis and superimpose newer prices to determine their impact on the results. For SO2 allowances, we assumed the same annual emissions and used the SO2 forward prices from December 9, 2004. We further assumed that prices after 2009 would remain at the average for the period 2005-2009. The impact was to increase the average price by approximately $500/ton. The average additional emissions for the with Noranda case was approximately 9,000 tons per year. This would create an increase of approximately $4.5 million per year or $0.11 per MWh. This method was repeated for NOx allowances with a resultant increase of approximately $1 million per year or $0.03 per MWh. The impact of using a newer market price forecast from mid-October would result in an increased value of off-system sales to the without Noranda case of approximately $0.6 million per year or $0.02 per MWh. The final sensitivity was a review of changes in natural gas prices between May and December. In general, summer natural gas prices have been forecasted to change on average less than 5%. In addition, AmerenUE's use of natural gas to generate electricity is small, less than 5%. Calculations underlying the sensitivity analyses are attached as Schedules RAV-10 – RAV-13 attached hereto and incorporated herein.

Q. Please summarize the total impact from the sensitivities which you performed.

A. The combined impact decreased the difference between the with Noranda and without Noranda cases by only $0.16 per MWh. In other words, the sensitivity analyses suggested that there could be a very slight decrease in the benefits of adding Noranda as a native load customer of AmerenUE.

Q. Comment further on the magnitude of a $0.16/MWh potential decrease in costs relative to a base gain of approximately $2.70/MWh under the Native Load Approach.

A. The decrease would lower the net benefit from $2.70/MWh to $2.54/MWh – approximately a 6% decrease.

Q. Did others perform any sensitivities on the analysis?

A. Yes. Dr. Proctor performed a sensitivity analysis relating to potential lost opportunities for off-system sales margins (profits). Dr. Proctor attempted to answer the question of how much off-system sales would have to increase in order for the potential lost off-system sales margins to offset the $/MWh cost reduction from adding the Noranda load to AmerenUE's native load. The results of Dr. Proctor's sensitivity analysis are shown in Slide 14 of his PowerPoint presentation (Appendix B hereto).

Q. What were the results of Dr. Proctor's sensitivity analysis?

A. Dr. Proctor's analysis shows that AmerenUE's off-system sales would have to <u>almost triple</u> in order for the addition of the Noranda load to result in a net loss to AmerenUE's existing customers.

Q. Do you agree with the results of Dr. Proctor's analysis?

A. I agree in concept. However, the reality of increasing off-system sales by such a large amount would necessitate that AmerenUE run its higher cost generation.

Q. Is it reasonable to assume that UE off-system sales margins could triple?

A. No. Historical off-system load sales show that the level of off-system sales used in AmerenUE's analysis is reasonable. Transmission export limitations along with market depth issues are two factors that limit AmerenUE's ability to significantly increase off-system sales. Thus, it is a virtual certainty that AmerenUE could not increase its off-system sales to a level that would cause any lost margins (profits) from off-system sales due to adding Noranda to offset the lower costs that adding Noranda will produce.

VII. <u>Summary.</u>

Q. Please summarize the conclusions that can be drawn from your testimony.

A. AmerenUE's ability to serve Noranda in 2005 is a function of acquiring capacity related to the AmerenUE transfer of its Metro East load and the acquisition of the Kinmundy/Pinckneyville CTGs by AmerenUE, together with the addition of 600 MW of additional peaking resources by summer 2006. Assuming these transactions occur, AmerenUE expects to have sufficient resources to meet all load through 2007. AmerenUE intends to meet its post 2007 capacity requirements through interim peaking capacity purchases while it builds new capacity resources pursuant to its twenty year resource plan. The cost analyses performed as discussed in my testimony indicate that AmerenUE's production costs per MWh are on average less with Noranda than without Noranda.

Q. Does this conclude your testimony?

A. Yes.

QUALIFICATIONS OF RICHARD A. VOYTAS

My name is Richard A. Voytas and my business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, MO 63103. I reside in St. Louis, MO.

My educational background consists of a Bachelor of Science degree in Mechanical Engineering from the University of Missouri-Rolla in 1975 and a Masters in Business Administration from St. Louis University in 1979. I am a registered professional engineer in the state of Missouri.

I was employed full time by Union Electric Company beginning in May of 1975. Effective with the merger of Union Electric Company and Central Illinois Public Service Company into the Ameren Corporation, I assumed employment with Ameren Services. My work experience started at Union Electric Company as an Assistant Engineer in the Engineering and Construction function. I worked as an Assistant Engineer from 1975 to 1977. In 1977 I was promoted to Fuel Buyer in the Supply Services Function. In 1981 I transferred to the Engineering Department at Union Electric Company's Rush Island Plant. In 1982 I accepted a position in the coal marketing department at Cities Service Company in Tulsa, OK. In late 1982 I left Cities Service Company and returned to Union Electric Company as an Engineer in the Corporate Planning Department. From 1982 through 1992 I worked as an Engineer in the Corporate Planning Department, Engineer in the Quality Improvement Department, and Engineer in the Rate Engineering Department. In 1993 I was promoted to Senior Engineer in the Corporate Planning Department. In 1995 I was promoted to Supervising Engineer in the Demand-Side Management section of Corporate Planning. In July 1998 the Resource Planning, Forecasting, Load Research and Demand-Side Management sections were combined into one section of Corporate Planning and I was named Supervisor of that section known as the Corporate Analysis Department. Today, Corporate Analysis is divided into four subgroups, which are Resource Planning, Market Modeling, Load Analysis and Forecasting, and Load Research. In October 2001 I was promoted to my present position as Manager-Corporate Analysis.

My duties as Manager of Corporate Analysis include overseeing the preparation of the capacity position of the operating companies owned by Ameren Corporation, both on an annual and weekly basis, preparation of resource plans, development and evaluation of requests and proposals for capacity and energy for Ameren operating companies, preparation of the annual sales and peak demand forecasts, development of the forward view of electric energy market prices, and the collection, editing and analysis of monthly load research data.

I have submitted testimony concerning least cost planning and weather normalization of sales before the Missouri Public Service Commission and the Illinois Commerce Commission. I have also submitted testimony to the Federal Energy Regulatory Commission regarding various power purchases and asset acquisitions.

AmerenUE Cost Comparison With and Without Noranda

Mike Proctor

December 10, 2004

All Results Are DRAFT

Basic Components: With & W/O Noranda Load

- Native Load Production Costs
- Native Load Embedded Costs
- Native Load Capacity Costs for Added Capacity
- Margin (Profits) from Off-System Sales
  - ✓Included as the last step in the analysis

Native Load Production Costs

- "Total" Production Costs
  - \+ Fuel,
  - \+ Variable O&M
  - \+ Fixed O&M
- Emission Costs
  - \+ SO2 Costs
  - \+ NOx Costs
- Off-System, Market Costs
  - \+ Purchased Power Costs
  - – Wholesale Production Costs (sales)

Native Load Embedded Costs

- Excludes Production Cost
- Add $18 M for A&G allocation for Noranda

	UE - IL
Admin & Gen'l Operating Expenses	17,613,739

Native Load Capacity Costs

- For Added Generation
- $471/kW for 600 MW of CTs required for Noranda
- Estimates for Coal and other CTs

Cost/kW	FChrg %	($1,000)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
$1,800	14.59%	Coal	$0	$0	$0	$0	$0	$0	$196,960	$196,960	$196,960	$196,960	$196,960	$196,960
$520	14.10%	Aero	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$440	14.10%	Sm Frame	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$410	14.10%	Lg Frame	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,501
		Total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$196,960**	**$196,960**	**$196,960**	**$196,960**	**$196,960**	**$215,461**

Endpoint 3 Results
Coal / With Noranda

Endpoint 3 - Noranda / Coal	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Total Production Cost ($mm)	$695	$735	$771	$796	$822	$846	$882	$929	$961	$986
SO2 Emissions Cost ($mm)	$48	$47	$46	$45	$42	$28	$25	$23	$22	$21
NOx Emissions Cost ($mm)	$0	$0	$33	$23	$22	$15	$14	$14	$14	$13
Wholesale Market Cost ($)mm	$8	$10	$5	$5	$2	$1	$1	$0	$0	$1
Wholesale Production Cost ($mm)	-$68	-$65	-$69	-$69	-$86	-$85	-$98	-$118	-$122	-$118
Total Production Costs - Native Load	$684	$727	$785	$800	$804	$805	$824	$848	$876	$902
Native Load (GWh)	36548	38781	39336	39663	39509	39868	40335	40985	41378	41833
Native Load Production Cost ($/MWh)	**$18.71**	**$18.76**	**$19.97**	**$20.16**	**$20.34**	**$20.19**	**$20.43**	**$20.69**	**$21.16**	**$21.57**
Embedded Costs	$1,686	$1,686	$1,686	$1,686	$1,686	$1,686	$1,686	$1,686	$1,686	$1,686
Added A&G - Noranda	**$18**	$18	$18	$18	$18	$18	$18	$18	$18	$18
Total	$1,704	$1,704	$1,704	$1,704	$1,704	$1,704	$1,704	$1,704	$1,704	$1,704
Native Load (GWh)	36548	38781	39336	39663	39509	39868	40335	40985	41378	41833
Embedded Costs $/MWh	**$46.62**	**$43.94**	**$43.32**	**$42.96**	**$43.13**	**$42.74**	**$42.25**	**$41.58**	**$41.18**	**$40.73**
Capacity Costs - Added CTs ($mm)	$0	$26	$41	$41	$41	$41	$41	$41	$41	$41
Capacity Costs - Base CTs ($mm)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capacity Costs - Coal ($mm)	$0	$0	$0	$0	$0	$0	$197	$197	$197	$197
Capacity Costs - Total ($mm)	$0	$26	$41	$41	$41	$41	$238	$238	$238	$238
Native Load (GWh)	36548	38781	39336	39663	39509	39868	40335	40985	41378	41833
Capacity Cost ($/MWh)	**$0.00**	**$0.66**	**$1.04**	**$1.03**	**$1.03**	**$1.02**	**$5.90**	**$5.80**	**$5.75**	**$5.68**

Endpoint 1 Results
Coal / Without Noranda

Endpoint 1 - No Naranda / Coal	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Total Production Cost ($mm)	$679	$700	$730	$750	$772	$795	$830	$869	$897	$920
SO2 Emissions Cost ($mm)	$46	$44	$43	$42	$39	$26	$23	$21	$21	$19
NOx Emissions Cost ($mm)	$0	$0	$30	$21	$20	$14	$13	$13	$13	$12
Wholesale Market Cost ($)mm	$1	$2	$1	$1	$0	$0	$0	$0	$0	$0
Wholesale Production Cost ($mm)	-$81	-$78	-$83	-$80	-$93	-$95	-$103	-$115	-$117	-$118
Total Production Costs - Native Load	$645	$668	$722	$734	$738	$740	$763	$788	$813	$833
Native Load (GWh)	34029	34945	35442	35782	35564	35895	36396	37090	37479	37777
Native Load Production Cost ($/MWh)	**$18.96**	**$19.12**	**$20.38**	**$20.51**	**$20.76**	**$20.61**	**$20.97**	**$21.24**	**$21.69**	**$22.05**
Embedded Costs	$1,686	$1,686	$1,686	$1,686	$1,686	$1,686	$1,686	$1,686	$1,686	$1,686
Native Load (GWh)	34029	34945	35442	35782	35564	35895	36396	37090	37479	37777
Embedded Costs $/MWh	**$49.56**	**$48.26**	**$47.58**	**$47.13**	**$47.42**	**$46.98**	**$46.33**	**$45.47**	**$45.00**	**$44.64**
Capacity Costs - Added CTs ($m)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capacity Costs - Base CTs ($m)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capacity Costs - Coal ($m)	$0	$0	$0	$0	$0	$0	$197	$197	$197	$197
Capacity Costs - Total ($m)	$0	$0	$0	$0	$0	$0	$197	$197	$197	$197
Native Load (GWh)	34029	34945	35442	35782	35564	35895	36396	37090	37479	37777
Capacity Cost ($/MWh)	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$5.41**	**$5.31**	**$5.26**	**$5.21**

Comparison
With Noranda – W/O Noranda
Endpoint 3 – Endpoint 1

Comparison Endpoint 3 to 1:	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Total Costs - #3 with Noranda ($mm)	$2,388	$2,457	$2,530	$2,544	$2,549	$2,550	$2,766	$2,790	$2,817	$2,844
Total Costs - #1 w/o Noranda ($mm)	$2,332	$2,355	$2,409	$2,420	$2,425	$2,426	$2,647	$2,671	$2,696	$2,716
Difference ($mm)	$56	$102	$121	$124	$124	$123	$119	$119	$121	$128
Total Costs - #3 with Noranda ($/MWh)	$65.33	$63.35	$64.32	$64.15	$64.51	$63.95	$68.57	$68.07	$68.09	$67.99
Total Costs - #1 w/o Noranda ($/MWh)	$68.52	$67.38	$67.96	$67.64	$68.18	$67.59	$72.71	$72.01	$71.94	$71.90
Difference ($/MWh)	**-$3.19**	**-$4.02**	**-$3.64**	**-$3.49**	**-$3.67**	**-$3.64**	**-$4.15**	**-$3.94**	**-$3.85**	**-$3.92**

Ignoring Off-System Sales, adding the Noranda load appears to lower cost per MWH on the average of $4/MWh.

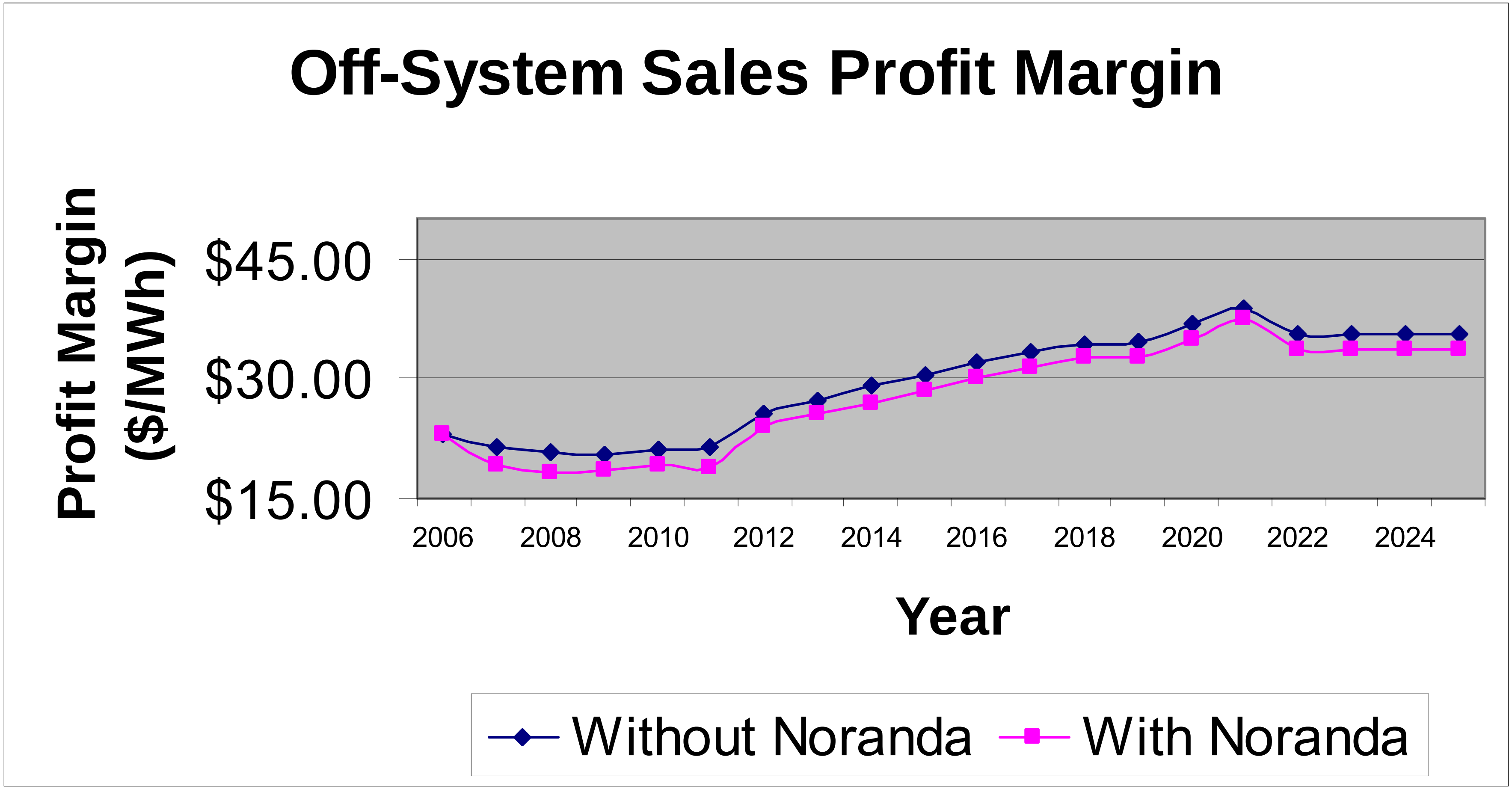
Profit Margin From Off-System Sales

Endpoint 1: W/O Noranda	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Wholesale Revenues	$244	$212	$213	$203	$238	$238	$284	$324	$332	$335
Wholesale Prod Costs	-$81	-$78	-$83	-$80	-$93	-$95	-$103	-$115	-$117	-$118
Margin ($mm)	$163	$135	$130	$123	$145	$143	$181	$210	$215	$217
Wholesale Load	7029	6252	6311	6039	6886	6648	7078	7665	7414	7108
Margin ($/MWh)	$23.17	$21.53	$20.66	$20.41	$21.06	$21.56	$25.59	$27.34	$29.04	$30.49

Endpoint 3: With Noranda	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Wholesale Revenues	$197	$161	$157	$159	$196	$185	$244	$303	$306	$297
Wholesale Prod Costs	-$68	-$65	-$69	-$69	-$86	-$85	-$98	-$118	-$122	-$118
Margin ($mm)	$129	$96	$88	$90	$111	$100	$146	$185	$185	$179
Wholesale Load	5628	5043	4843	4853	5796	5283	6135	7219	6852	6246
Margin ($/MWh)	$22.95	$19.11	$18.16	$18.57	$19.09	$19.01	$23.85	$25.65	$26.94	$28.65

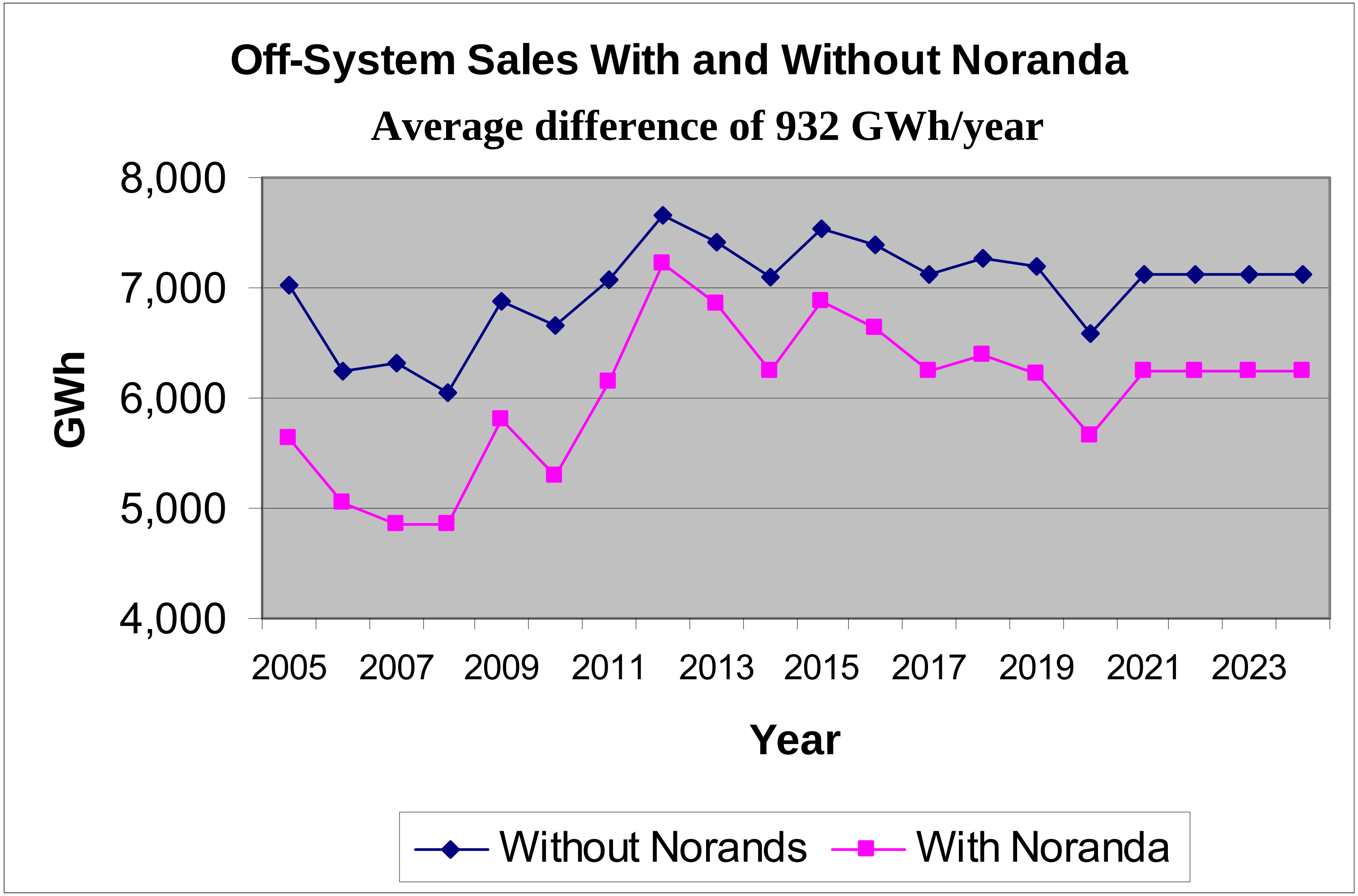
Ameren's analysis assumes that energy not needed to serve Native Load will be sold into the market up to the point where marginal costs is less than or equal to the market price or where the export limit is reached, whichever gives the smaller level of off-system sales.

Comparing Profit Margins With and Without Norand

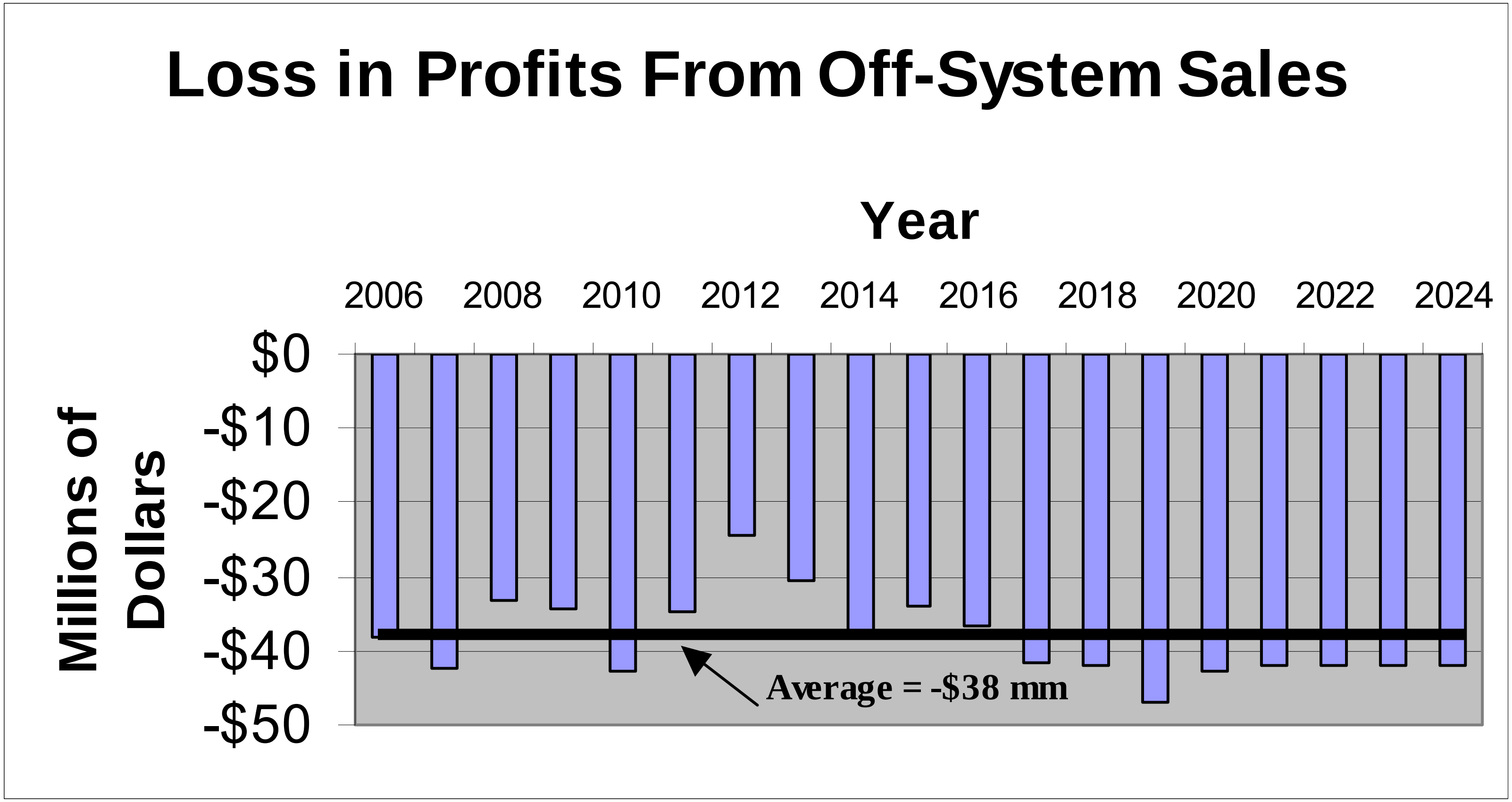


Appendix B

Comparing Off-System Sales With and Without Noranda



Comparing Profits From Off-System Sales With and Without Noranda



Off-System Sales Margin With and Without Noranda At 100% to AmerenUE

Assumed % of Profits to AmerenUE	**100%**	**$2.43**	**Average Net Gain over first ten years**							
Diff in Wholesale Sales Margin	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Endpoint 3 Margin ($mm)	$129	$96	$88	$90	$111	$100	$146	$185	$185	$179
Endpoint 3 Native Load (GWh)	36548	38781	39336	39663	39509	39868	40335	40985	41378	41833
Savings to Native Load ($/MWh)	$3.53	$2.49	$2.24	$2.27	$2.80	$2.52	$3.63	$4.52	$4.46	$4.28
Endpoint 1 Margin ($mm)	$163	$135	$130	$123	$145	$143	$181	$210	$215	$217
Endpoint 1 Native Load (GWh)	34029	34945	35442	35782	35564	35895	36396	37090	37479	37777
Savings to Native Load ($/MWh)	$4.79	$3.85	$3.68	$3.44	$4.08	$3.99	$4.98	$5.65	$5.74	$5.74
Loss in Savings from Margin ($/MWh)	**-$1.25**	**-$1.37**	**-$1.44**	**-$1.17**	**-$1.28**	**-$1.47**	**-$1.35**	**-$1.13**	**-$1.28**	**-$1.46**
Calculation of Net Gain (Loss)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Gain w/o Wholeale Margin	$3.19	$4.02	$3.64	$3.49	$3.67	$3.64	$4.15	$3.94	$3.85	$3.92
Loss from Wholesale Margin	-$1.25	-$1.37	-$1.44	-$1.17	-$1.28	-$1.47	-$1.35	-$1.13	-$1.28	-$1.46
Net Gain (Loss)	$1.94	$2.66	$2.20	$2.31	$2.39	$2.17	$2.80	$2.81	$2.57	$2.46

Under the assumption that 100% of the profit margin calculated in AmerenUE’s model are passed on as savings in production costs to AmerenUE’s Native Load customers, there is a Net Gain to AmerenUE’s existing customers from serving the Noranda Load.

Sensitivity on Off-System Sales

Assumed % of Profits to AmerenUE	284%	$0.00	Average Net Gain over first ten years							
Diff in Wholesale Sales Margin	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Endpoint 3 Margin ($mm)	$367	$274	$250	$256	$314	$285	$416	$526	$524	$508
Endpoint 3 Native Load (GWh)	36548	38781	39336	39663	39509	39868	40335	40985	41378	41833
Savings to Native Load ($/MWh)	$10.04	$7.06	$6.35	$6.45	$7.95	$7.15	$10.30	$12.83	$12.67	$12.15
Endpoint 1 Margin ($mm)	$463	$382	$370	$350	$412	$407	$514	$595	$611	$616
Endpoint 1 Native Load (GWh)	34029	34945	35442	35782	35564	35895	36396	37090	37479	37777
Savings to Native Load ($/MWh)	$13.59	$10.94	$10.45	$9.78	$11.58	$11.34	$14.13	$16.05	$16.31	$16.29
Loss in Savings from Margin ($/MWh)	**-$3.56**	**-$3.88**	**-$4.10**	**-$3.33**	**-$3.63**	**-$4.19**	**-$3.83**	**-$3.22**	**-$3.64**	**-$4.15**
Calculation of Net Gain (Loss)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Gain w/o Wholeale Margin	$3.19	$4.02	$3.64	$3.49	$3.67	$3.64	$4.15	$3.94	$3.85	$3.92
Loss from Wholesale Margin	-$3.56	-$3.88	-$4.10	-$3.33	-$3.63	-$4.19	-$3.83	-$3.22	-$3.64	-$4.15
Net Gain (Loss)	-$0.36	$0.15	-$0.46	$0.16	$0.04	-$0.54	$0.32	$0.73	$0.21	-$0.23

AmerenUE’s off-system sales would have to almost triple in order for the Noranda transfer to result in a net loss to AmerenUE’s existing customers.

THIS SCHEDULE
IS DEEMED
HIGHLY CONFIDENTIAL

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Noranda Analysis - Proctor Method
Endpoint 3 - Noranda Case - Buy CTG plant, Build PC & CTGs

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Native Market Sold (GWh)	36750	38923	39492	39891	39598	39964	40393	40995	41390	41842	42215	42629	43108	43471	43898	44374	44855	45342	45834	46331
to MO retail	36132	38292	38850	39239	39598	39964	40393	40995	41390	41842	42215	42629	43108	43471	43898	44374	44855	45342	45834	46331
to MO wholesale	618	631	642	653	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Off-System Sold (GWh)	5628	5043	4843	4853	5796	5283	6135	7219	6852	6246	6873	6646	6253	6386	6227	5654	6233	6233	6233	6233
Off-System Bought (GWh)	202	142	156	229	90	95	58	11	12	9	6	15	17	27	21	89	34	34	34	34
Off-System Purchase Cost ($)mm	$12.6	$8.1	$8.3	$10.4	$4.5	$4.9	$2.4	$0.6	$0.7	$0.5	$0.4	$0.9	$1.0	$1.7	$1.3	$5.4	$2.8	$2.8	$2.8	$2.8
Off-System Production Cost ($mm)	$68	$65	$69	$69	$86	$85	$98	$118	$122	$118	$131	$134	$134	$135	$143	$133	$136	$136	$136	$136
Total Production Cost ($mm)	$695	$735	$771	$796	$822	$846	$882	$929	$961	$986	$1,018	$1,052	$1,085	$1,110	$1,152	$1,179	$1,192	$1,204	$1,218	$1,231
Native Production Cost ($mm)	$627	$670	$702	$727	$737	$761	$784	$811	$840	$868	$887	$919	$950	$975	$1,010	$1,046	$1,056	$1,069	$1,082	$1,095
for MO retail	$615	$657	$689	$713	$737	$761	$784	$811	$840	$868	$887	$919	$950	$975	$1,010	$1,046	$1,056	$1,069	$1,082	$1,095
for MO wholesale	$12	$13	$13	$14	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Off-System Revenue ($mm)	$197	$161	$157	$159	$196	$185	$244	$303	$306	$297	$339	$343	$338	$343	$360	$344	$346	$346	$346	$346
Native Margin ($mm)	$123	$91	$79	$83	$102	$95	$141	$180	$180	$175	$204	$206	$200	$205	$214	$209	$207	$207	$207	$207
to MO retail	$120	$89	$78	$81	$102	$95	$141	$180	$180	$175	$204	$206	$200	$205	$214	$209	$207	$207	$207	$207
to MO wholesale	$2	$2	$1	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SO2 Emissions Cost ($mm)	$48.2	$46.9	$46.1	$45.5	$42	$28	$25	$23	$22	$21	$15	$15	$15	$15	$15	$15	$15	$15	$15	$15
Native SO2 Emissions Cost ($mm)	$41.8	$41.5	$37.4	$38.1	$33.8	$22.5	$19.9	$17.4	$17.0	$16.1	$11.2	$11.6	$11.9	$11.6	$12.0	$12.3	$12.0	$12.0	$12.0	$12.1
for MO retail	$41.0	$40.8	$36.7	$37.4	$33.8	$22.5	$19.9	$17.4	$17.0	$16.1	$11.2	$11.6	$11.9	$11.6	$12.0	$12.3	$12.0	$12.0	$12.0	$12.1
for MO wholesale	$0.8	$0.8	$0.7	$0.7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NOx Emissions Cost ($mm)	$0.0	$0.0	$33.0	$22.6	$22	$15	$14	$14	$14	$13	$10	$11	$11	$11	$11	$11	$11	$11	$11	$11
for MO retail	$0.0	$0.0	$32.4	$22.1	$22.4	$15.4	$14.2	$13.8	$13.7	$13.2	$10.3	$10.7	$10.5	$10.6	$10.9	$10.8	$10.7	$10.7	$10.7	$10.7
for MO wholesale	$0.0	$0.0	$0.6	$0.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Off-System Emissions Cost ($mm)	$6	$5	$9	$7	$8	$5	$5	$5	$5	$4	$4	$3	$3	$3	$3	$3	$3	$3	$3	$3
Energy Cost, $/MWH	$15.18	$16.11	$17.71	$17.88	$17.56	$17.73	$16.82	$16.17	$16.70	$17.28	$16.70	$17.27	$17.95	$18.25	$18.67	$19.51	$19.50	$19.57	$19.65	$19.72
Embedded Cost, $/MWH	$46.40	$43.79	$43.16	$42.73	$43.19	$42.80	$42.34	$41.72	$41.32	$40.88	$40.51	$40.12	$39.68	$39.34	$38.96	$38.54	$38.13	$37.72	$37.32	$36.92
New Capacity Charge, $/MWH	$0.00	$0.65	$1.03	$1.02	$1.03	$1.02	$5.89	$5.80	$5.75	$5.68	$5.63	$6.01	$5.95	$5.90	$6.26	$6.19	$6.29	$6.38	$6.32	$6.65
Total Cost, $/MWH	**$61.58**	**$60.55**	**$61.90**	**$61.63**	**$61.78**	**$61.55**	**$65.05**	**$63.69**	**$63.77**	**$63.84**	**$62.85**	**$63.40**	**$63.57**	**$63.49**	**$63.89**	**$64.25**	**$63.92**	**$63.68**	**$63.28**	**$63.29**
Diff: Noranda less No Noranda	**-$2.63**	**-$3.41**	**-$2.83**	**-$2.99**	**-$2.99**	**-$2.71**	**-$3.35**	**-$3.31**	**-$3.06**	**-$2.96**	**-$2.84**	**-$2.68**	**-$2.57**	**-$2.44**	**-$2.19**	**-$2.27**	**-$2.53**	**-$2.60**	**-$2.83**	**-$2.48**
Percent Difference	**-4.1%**	**-5.3%**	**-4.4%**	**-4.6%**	**-4.6%**	**-4.2%**	**-4.9%**	**-4.9%**	**-4.6%**	**-4.4%**	**-4.3%**	**-4.1%**	**-3.9%**	**-3.7%**	**-3.3%**	**-3.4%**	**-3.8%**	**-3.9%**	**-4.3%**	**-3.8%**

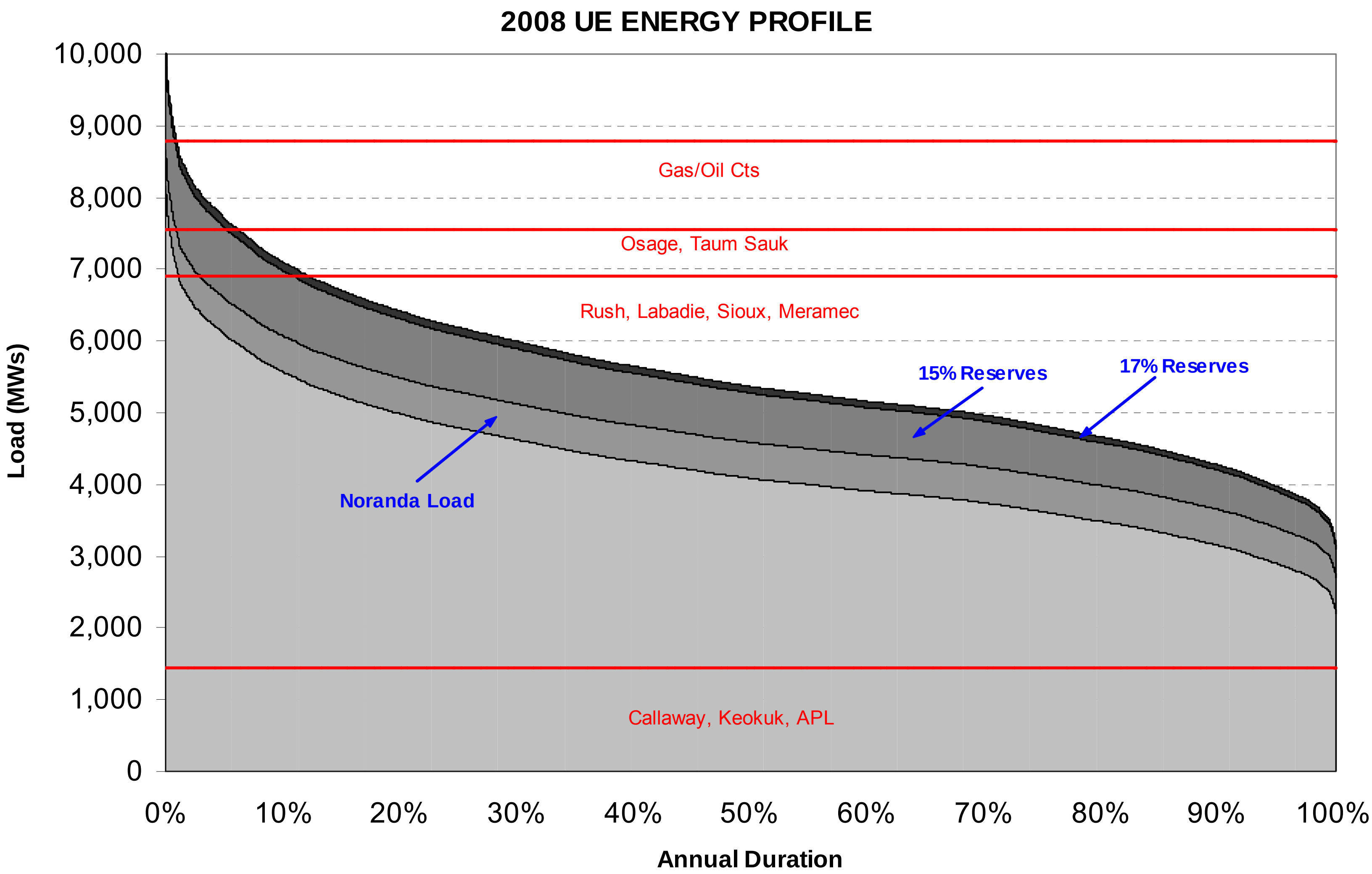
Average Cost Difference, $/MWH	2005	2006	2007	2008	2005-14	2005-24
Scenario 3 less Scenario 1	-$2.63	-$3.41	-$2.83	-$2.99	**-$3.02**	**-$2.78**
Scenario 4 less Scenario 2	-$2.63	-$4.06	-$3.21	-$2.99	**-$2.83**	**-$2.38**

Noranda Analysis - Ameren Method
Endpoint 3 - Noranda Case - Buy CTG plant, Build PC & CTGs

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Native Market Sold (GWh)	36750	38923	39492	39891	39598	39964	40393	40995	41390	41842	42215	42629	43108	43471	43898	44374	44855	45342	45834	46331
to MO retail	36132	38292	38850	39239	39598	39964	40393	40995	41390	41842	42215	42629	43108	43471	43898	44374	44855	45342	45834	46331
to MO wholesale	618	631	642	653	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Off-System Sold (GWh)	5628	5043	4843	4853	5796	5283	6135	7219	6852	6246	6873	6646	6253	6386	6227	5654	6233	6233	6233	6233
Off-System Bought (GWh)	202	142	156	229	90	95	58	11	12	9	6	15	17	27	21	89	34	34	34	34
Off-System Purchase Cost ($)mm	$12.6	$8.1	$8.3	$10.4	$4.5	$4.9	$2.4	$0.6	$0.7	$0.5	$0.4	$0.9	$1.0	$1.7	$1.3	$5.4	$2.8	$2.8	$2.8	$2.8
Off-System Production Cost ($mm)	$68	$65	$69	$69	$86	$85	$98	$118	$122	$118	$131	$134	$134	$135	$143	$133	$136	$136	$136	$136
Total Production Cost ($mm)	$695	$735	$771	$796	$822	$846	$882	$929	$961	$986	$1,018	$1,052	$1,085	$1,110	$1,152	$1,179	$1,192	$1,204	$1,218	$1,231
Native Production Cost ($mm)	$627	$670	$702	$727	$737	$761	$784	$811	$840	$868	$887	$919	$950	$975	$1,010	$1,046	$1,056	$1,069	$1,082	$1,095
for MO retail	$615	$657	$689	$713	$737	$761	$784	$811	$840	$868	$887	$919	$950	$975	$1,010	$1,046	$1,056	$1,069	$1,082	$1,095
for MO wholesale	$12	$13	$13	$14	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Off-System Revenue ($mm)	$197	$161	$157	$159	$196	$185	$244	$303	$306	$297	$339	$343	$338	$343	$360	$344	$346	$346	$346	$346
Native Margin ($mm)	$123	$91	$79	$83	$102	$95	$141	$180	$180	$175	$204	$206	$200	$205	$214	$209	$207	$207	$207	$207
to MO retail	$120	$89	$78	$81	$102	$95	$141	$180	$180	$175	$204	$206	$200	$205	$214	$209	$207	$207	$207	$207
to MO wholesale	$2	$2	$1	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SO2 Emissions Cost ($mm)	$48.2	$46.9	$46.1	$45.5	$42	$28	$25	$23	$22	$21	$15	$15	$15	$15	$15	$15	$15	$15	$15	$15
Native SO2 Emissions Cost ($mm)	$41.8	$41.5	$37.4	$38.1	$33.8	$22.5	$19.9	$17.4	$17.0	$16.1	$11.2	$11.6	$11.9	$11.6	$12.0	$12.3	$12.0	$12.0	$12.0	$12.1
for MO retail	$41.0	$40.8	$36.7	$37.4	$33.8	$22.5	$19.9	$17.4	$17.0	$16.1	$11.2	$11.6	$11.9	$11.6	$12.0	$12.3	$12.0	$12.0	$12.0	$12.1
for MO wholesale	$0.8	$0.8	$0.7	$0.7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
NOx Emissions Cost ($mm)	$0.0	$0.0	$33.0	$22.6	$22	$15	$14	$14	$14	$13	$10	$11	$11	$11	$11	$11	$11	$11	$11	$11
for MO retail	$0.0	$0.0	$32.4	$22.1	$22.4	$15.4	$14.2	$13.8	$13.7	$13.2	$10.3	$10.7	$10.5	$10.6	$10.9	$10.8	$10.7	$10.7	$10.7	$10.7
for MO wholesale	$0.0	$0.0	$0.6	$0.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Off-System Emissions Cost ($mm)	$6	$5	$9	$7	$8	$5	$5	$5	$5	$4	$4	$3	$3	$3	$3	$3	$3	$3	$3	$3
Energy Cost, $/MWH	$13.19	$14.30	$15.82	$15.98	$15.32	$15.66	$14.60	$13.75	$14.33	$15.03	$14.36	$14.94	$15.67	$15.91	$16.35	$17.31	$17.12	$17.21	$17.30	$17.38
Embedded Cost, $/MWH	$40.36	$38.90	$38.58	$38.22	$37.68	$37.80	$36.76	$35.47	$35.45	$35.57	$34.84	$34.71	$34.65	$34.30	$34.12	$34.19	$33.48	$33.16	$32.85	$32.54
New Capacity Charge, $/MWH	$0.00	$0.58	$0.92	$0.91	$0.90	$0.90	$5.11	$4.93	$4.93	$4.95	$4.84	$5.20	$5.19	$5.14	$5.48	$5.49	$5.52	$5.61	$5.56	$5.86
Total Cost, $/MWH	**$53.55**	**$53.78**	**$55.31**	**$55.12**	**$53.89**	**$54.36**	**$56.47**	**$54.16**	**$54.71**	**$55.55**	**$54.05**	**$54.85**	**$55.52**	**$55.36**	**$55.96**	**$56.99**	**$56.12**	**$55.98**	**$55.70**	**$55.78**
Diff: Noranda less No Noranda	**$0.17**	**-$0.65**	**$0.20**	**-$0.34**	**-$0.37**	**$0.14**	**-$0.79**	**-$1.37**	**-$1.08**	**-$0.67**	**-$0.81**	**-$0.63**	**-$0.41**	**-$0.32**	**-$0.06**	**-$0.19**	**-$0.44**	**-$0.51**	**-$0.71**	**-$0.42**
Percent Difference	**0.3%**	**-1.2%**	**0.4%**	**-0.6%**	**-0.7%**	**0.3%**	**-1.4%**	**-2.5%**	**-1.9%**	**-1.2%**	**-1.5%**	**-1.1%**	**-0.7%**	**-0.6%**	**-0.1%**	**-0.3%**	**-0.8%**	**-0.9%**	**-1.3%**	**-0.7%**

Average Cost Difference, $/MWH	**2005**	**2006**	**2007**	**2008**	**2005-14**	**2005-24**
Scenario 3 less Scenario 1	$0.17	-$0.65	$0.20	-$0.34	**-$0.48**	**-$0.46**
Scenario 4 less Scenario 2	$0.17	-$1.23	-$0.14	-$0.34	**-$0.21**	**$0.09**

2008 AMERENUE LOAD DURATION CURVE



Example - Mathematics of Native Load Approach v. Total System Approach

(Using 2008 for Illustration)

	2008		
	w/o Noranda	**w/ Noranda**	
Total Costs (thousands $)	$2,321,552	$2,466,168	
Native Load (GWh)	35,821	39,891	
Off-System sales (GWh)	6,039	4,853	
			Difference of Options
Native Customer Avg Cost ($/MWh)	$64.81	$61.82	$2.99
System Avg Cost ($/MWh)	$55.46	$55.12	$0.34

Example Calculations

Without Noranda

Native Customer Avg Cost	=	Total Cost	/		Native Load			
$64.81	=	$2,321,552	/		35,821			
System Avg Cost	=	Total Cost	/	(	Native Load	+	Off-System sales	)
$55.46	=	$2,321,552	/	(	35,821	+	6,039	)

With Noranda

Native Customer Avg Cost	=	Total Cost	/		Native Load			
$61.82	=	$2,466,168	/		39,891			
System Avg Cost	=	Total Cost	/	(	Native Load	+	Off-System sales	)
$55.12	=	$2,466,168	/	(	39,891	+	4,853	)

Sensitivity - SO2 Calculations								
SO2 Emissions					SO2 Allowance Price			
Year	Endpoint 1	Endpoint 3	Difference		Year	Noranda Study	12/9/2004 Price	Difference
2005	142,265	148,383	6,118		2005	325	709	385
2006	135,505	145,529	10,024		2006	323	705	383
2007	138,112	147,454	9,342		2007	313	695	383
2008	139,925	149,835	9,910		2008	304	680	377
2009	139,915	149,952	10,037		2009	281	610	330
2010	143,270	152,768	9,498		2010	180		
2011	137,571	147,161	9,590		2011	170		
2012	132,868	142,999	10,131		2012	160		
2013	137,144	146,900	9,756		2013	150		
2014	137,450	146,465	9,015		2014	140		
2015	138,026	147,263	9,237		2015	100		
2016	142,264	151,142	8,878		2016	100		
2017	142,745	151,341	8,596		2017	100		
2018	140,263	148,932	8,669		2018	100		
2019	145,349	153,077	7,728		2019	100		
2020	143,919	152,065	8,146		2020	100		
		Average:	9,042		Average:	184	680	371
Impact of using newer SO2 prices:				$4,483,399				
Load served (MWh):				40,000,000				
Impact of using newer SO2 prices ($/MWh):				$0.11				

Sensitivity - NOx Calculations								
NOx Emissions					NOx Allowance Price			
Year	Endpoint 1	Endpoint 3	Difference		Year	Noranda Study	12/9/2004 Price	Difference
2005	4	4	0		2005	3,075	3,325	250
2006	9	9	0		2006	3,000	3,200	200
2007	11,186	12,231	1,045		2007	2,700	2,775	75
2008	9,222	10,143	921		2008	2,225	2,650	425
2009	9,138	10,086	948		2009	2,225	2,300	75
2010	9,334	10,289	955		2010	1,500		
2011	8,821	9,770	949		2011	1,450		
2012	8,927	9,818	891		2012	1,400		
2013	9,257	10,175	918		2013	1,350		
2014	9,184	10,132	948		2014	1,300		
2015	9,364	10,319	955		2015	1,000		
2016	9,740	10,678	938		2016	1,000		
2017	9,534	10,499	965		2017	1,000		
2018	9,625	10,570	945		2018	1,000		
2019	10,016	10,940	924		2019	1,000		
2020	9,819	10,768	949		2020	1,000		
		Average:	828		Average:	1,639	2,850	205
Impact of using newer NOx prices:				$1,002,883				
Load served (MWh):				40,000,000				
Impact of using newer NOx prices ($/MWh):				$0.03				

Sensitivity - Updated Market Price Calculations								
Off System Sales (GWh)					7x24 Market Price			
Year	Endpoint 1	Endpoint 3	Difference		Year	Noranda Study	10/18/2004 FV	Difference
2005	7,029	5,628	-1,401		2005	34.23	36.71	2.48
2006	6,252	5,043	-1,209		2006	33.53	36.37	2.84
2007	6,311	4,843	-1,468		2007	33.49	35.52	2.03
2008	6,039	4,853	-1,186		2008	33.86	35.92	2.06
2009	6,886	5,796	-1,090		2009	34.62	35.73	1.11
2010	6,648	5,283	-1,365		2010	36.67	36.18	-0.49
2011	7,078	6,135	-944		2011	38.66	38.81	0.15
2012	7,665	7,219	-446		2012	40.68	40.70	0.02
2013	7,414	6,852	-562		2013	43.00	42.82	-0.18
2014	7,108	6,246	-862		2014	45.23	45.66	0.43
2015	7,541	6,873	-668		2015	47.45	47.42	-0.03
2016	7,391	6,646	-744		2016	49.03	49.09	0.06
2017	7,127	6,253	-874		2017	50.81	51.49	0.68
2018	7,263	6,386	-877		2018	51.83	52.05	0.22
2019	7,187	6,227	-959		2019	54.64	54.27	-0.37
2020	6,586	5,654	-933		2020	56.62	56.17	-0.45
		Average:	-974		Average:	42.77	43.43	0.66
Impact of using newer Market prices:				-$643,058				
Load served (MWh):				35,000,000				
Impact of using newer Market prices ($/MWh):				-$0.02				

Sensitivity - Updated Gas Price Calculations						
July Henry Hub Natural Gas Prices ($/MMBtu from NYMEX):						
					Difference	
Year	5/17/2004	10/18/2004	12/9/2004		5/17 - 10/18	5/17 - 12/09
2005	6.51	6.699	6.468		0.189	-0.042
2006	5.798	6.049	6.11		0.251	0.312
2007	5.376	5.573	5.72		0.197	0.344
2008	5.092	5.198	5.345		0.106	0.253
2009	4.939	4.868	5.03		-0.071	0.091
2010	4.839	4.658	4.873		-0.181	0.034
Average:	5.426	5.508	5.591		0.082	0.165
				% Change:	1.51%	3.05%

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served via e-mail, to the following parties on the 20th day of December, 2004.

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