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MISSOURI PUBLIC SERVICE COMMISSION
Case No. EA-2014-0207

REBUTTAL TESTIMONY

OF

MICHAEL S. PROCTOR

ON BEHALF OF

SHOW-ME CONCERNED LAND OWNERS

September 15, 2014

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Q. WHAT IS YOUR NAME, PRESENT POSITION AND ADDRESS?

A. My name is Michael S. Proctor. I am currently an independent consultant. My home address is 2172 Butterfield Drive, Maryland Heights, MO., 63043

Q. ON BEHALF OF WHAT PARTY TO THIS CASE ARE YOU TESTIFYING?

A. I am testifying on behalf of Show-Me Concerned Land Owners.

Q. WHAT IS YOUR EDUCATION AND PROFESSIONAL BACKGROUND?

A. I received a PhD in economics from Texas A&M University. I taught economics and management science at Purdue University and the University of Missouri. In 1977 I joined the staff of the Missouri Public Service Commission (Missouri Commission) where I was the Chief Economist. After retiring in 2009 I have consulted on a variety of issues related to transmission planning, cost allocation and markets for Regional Transmission Organizations. I currently have a consulting contract with the Regional State Committee (RSC) of the Southwest Power Pool (SPP). My curriculum vita is provided in **Schedule MSP-1** attached to my rebuttal testimony.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony will address the direst testimonies submitted on behalf of Grain Belt Express Clean Line by Mr. David Berry and Mr. Gary Moland. I have reviewed these testimonies, submitted data requests and reviewed appropriate work products of these witnesses. My rebuttal testimony will address issues I found with their analysis. An Executive Summary of my rebuttal testimony is found in Schedule MSP-2 attached to my rebuttal testimony.

I. REBUTTAL OF THE DIRECT TESTIMONY OF DAVID BERRY

A. OVERVIEW

Q. WHAT PORTIONS OF DAVID BERRY'S DIRECT TESTIMONY ARE YOU ADDRESSING?

A. The focus of my rebuttal testimony is on the Levelized Cost Analysis presented in Mr. Berry's direct testimony.

Q. WHAT IS A LEVELIZED COST ANALYSIS?

A. In regulated utility analysis, levelized costs represent the per-year revenue requirement to cover the return of and on investment as well as annual expenses over the life of the asset. Levelized cost is calculated by finding a constant year-to-year revenue requirement that has the same net present value as the actual year-to-year revenue requirements that decrease over time as net investment decreases.

Q. WHAT IS THE PURPOSE OF A LEVELIZED COST ANALYSIS?

A. Generally, the purpose of a levelized cost analysis is to provide a way to compare investment alternatives that have differing investment costs, expenses and asset lives.

Q. DO YOU AGREE WITH MR. BERRY THAT A LEVELIZED COST ANALYSIS IS APPROPROIATE FOR SHOWING THE ECONOMIC FEASIBILITY OF THE GRAIN BELT DC TRANSMISSION PROJECT?

A. Levelized cost analysis is an appropriate method to use in comparing resources that run at 100% of their capability; i.e., whose available generation is always dispatched. These are sometimes called based-loaded generation resources. The following table is an example of such a comparison for national average data from the Energy Information Agency (EIA) of the Department of Energy (DOE).

U. S. Average Levelized Cost (2011 $MWh for Plants Entering Service in 2018

(Source: EIA: Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013)

Project Type	Capacity Factor	Levelized Capital Costs	Fixed O&M	Variable O&M + Fuel	Transmission Investment	Total Levelized Cost
Convential Coal	85%	$65.70	$4.10	$29.20	$1.20	$100.20
Covential Combined Cycle	87%	$15.80	$1.70	$48.40	$1.20	$67.10
Wind	34%	$70.30	$13.10	$0.00	$3.20	$86.60

In the above table, the capacity factors represent the percent of time each project type is operating at 100% of their installed capacity. For conventional generation, the less than 100% represents the time units are forced out or are down for maintenance. For wind, the lower percentage represents the average availability of wind. The cited report notes that if a utility needs dispatchable generation, then levelized cost analysis is only used to eliminate generation alternatives that have higher costs across all levels of dispatchability. Once potentially economic generation alternatives are determined, least-cost generation resource combinations are determined using generation expansion models that evaluate energy production, energy costs and capacity costs of various alternatives over multiple years.

Q. WOULD IT BE CORRECT TO SAY THAT MR. BERRY'S USED LEVELIZED COST AS A SCREENING TOOL TO DETERMINE WHICH BASE-LOADED RESOURCES ARE MOST ECONOMIC?

A. Yes. Since the transmission cost of the Grain Belt DC transmission (DC Transmission) project is so high (estimated by Mr. Berry to be $15-$20 per MWh compared to just over $3/MWh for wind in the previous table), an analysis needs to be provided that shows the generation and transmission services from the wind farms in western Kansas are less costly than other base-loaded generation projects not requiring the same high cost transmission to deliver the power into the Ameren Missouri service area. Specifically, do the savings from the higher capacity factor of the western Kansas wind make up for the added cost for transmission? The remainder of my rebuttal testimony of Mr. Berry will look in-depth at his calculation of levelized costs for various resources, and correct those calculations where errors were made.

B. PRELIMINALY OBSERVATIONS ON MR. BERRY'S LEVELIZED COST ANALYSIS

Q. WHAT OVERALL ISSUE DID YOU FIND WITH MR. BERRY'S LEVELIZED COST ANALYSIS?

A. Mr. Berry did not perform his levelized cost analysis in the same way as is typically done for regulated utilities. Instead of calculating revenue requirements for a regulated utility that includes a return of and on total capital investment, Mr. Berry calculates the investment cost minus the net present value of tax depreciation. Mr. Berry also includes a value for the potential sale of capacity from the capital investment. The result is what Mr. Berry calls the "levelized cost of energy." Mr. Berry used the cost of a combustion turbine as the value of capacity. Even though Mr. Berry presents results with and without the added capacity value in graphical form on page 18 of his testimony, the calculations without capacity value do not reflect what regulated utilities would call levelized cost.

Q. WHAT IS METHOD USED BY REGULATED UTILITIES TO CALCULATE LEVELIZED COSTS?

A. The following table sets out the components for calculating the annual revenue requirements for a generation asset owned by a regulated utility. Net Investment is Gross Investment (Capital Cost of the asset) minus accumulated Straight- Line (S-L) Depreciation, and Tax Depreciation is typically accelerated compared to S-L Depreciation. The first five components comprise what are called "Capacity Costs," that include the return of and on investment as well as taxes related to the investment; i.e., income tax and property tax. The final two components are annual expenses. The annual revenue requirements include all costs that would be collected in rates from the utility's customers.

Return on Equity	(Equity Rate)*(Equity %)*(Net Investment)
Income Tax	(Tax Rate)*(Return on Equity – Tax Depreciation)
Interest on Debt	(Interest Rate)*(Net Investment)
Return of Investment	Straight-Line Depreciation = (Capital Cost/Asset Life)
Property Tax	(Tax Rate)*(% Assessment)*(Net Investment)
O&M Expense	Fixed O&M + Variable O&M
Fuel Expense	(Fuel Cost [($/MMBtu)*(MMBtu/MWh)]*(MWh)

Each year of revenue requirements is discounted to obtain the NPV of the annual revenue requirements over the asset life. The NPV of the revenue requirements are then divided by the sum of the annual discount factors to obtain a "levelized" (same dollar amount each year) revenue requirement, whose net present value (NPV) is equal to the NPV previously calculated on the non- levelized revenue requirements. To convert this levelized revenue requirement from dollars to $/MWh, the levelized revenue requirement is divided by the average annual MWh generation expected from the generation asset.

Q. WHAT OTHER ISSUES DO YOU HAVE WITH MR. BERRY'S CALCUATION OF "LEVELIZED ENERGY COST?"

A. Mr. Berry's calculation of what he calls the "capitalization factor" is incorrect. In Mr. Berry's calculations the assumed date of commercial operation is 2019 for all alternatives. Mr. Berry includes the Capacity Costs in 2018, and then takes the NPV of all components back to 2018. But when he calculates the capitalization factor he does not include the discount factor for 2018 when adding the discount factors over the life of the asset. The result is his capitalization factor is equal to the correct capitalization factor discounted back one year. Thus, his levelized costs are calculated by dividing by a capitalization factor that is too low, resulting in too high of a levelized cost.

Also, Mr. Berry confuses inflation rates with cost escalation over the asset life. This results in an overestimate of the annual O&M costs for most of the alternatives. In the case of wind, Mr. Berry combines the inflation rate with an escalation rate. I will discuss this case further in the next section of my rebuttal testimony.

Q. WHAT IS YOUR CONCLUSION REGARDING MR. BERRY'S CALCULATIONS OF "LEVELIZED ENERGY COSTS?"

A. His method of calculation does not conform to utility practice and therefore does not properly represent the cost that a regulated utility would have to pay. The Missouri Commission should treat Mr. Berry's estimates as inadequate for making a determination as to the economic viability of the DC Transmission project. In the remainder of my rebuttal to Mr. Berry I will provide levelized cost estimates that do conform to utility practice and do reflect the costs that a regulated utility would have to pay.

C. LEVELIZED COST FOR KANSAS WIND GENERATION

1. LEVELIZED CAPACITY COSTS

Q. WHAT DOES MR. BERRY ESTIMATE AS THE LEVELIZED COST FOR THE ENERGY FROM THE KANSAS WIND FARMS TO BE LOCATED AT THE SOURCE OF THE DC TRANSMISSION PROJECT?

A. According to Mr. Berry's worksheets which he provided to me, he estimated the levelized cost to be \$15/MWh.

Q. DID THIS ESTIMATE APPEAR TO BE REASONABLE?

A. At first, it did not. As a consultant for the SPP RSC I monitor the meetings of the Economic Studies Working Group (ESWG) that is responsible for the economic inputs that go into the SPP's Integrated Transmission Planning. As a part of that planning process, SPP must estimate what generation is most likely to be built to meet needs 10 and 20 years out. The basic generation alternatives considered are: nuclear; coal; combined cycle; combustion turbine, and wind. In the SPP analysis the lowest and most recent levelized cost for wind generation has been $35/MWh, not including annual O&M expense. This is in agreement with the latest price data reported in US Department of Energy's 2012 Wind Technologies Market Report (DOE 2012 WTMR) at page 35, where the average levelized Purchase Power Agreement prices for the interior region in 2011 and 2012 is above $30/MWh, and none of the prices are below $20/MWh.

Q. BY ANALYZING MR. BERRY'S WORK PAPERS HAVE YOU BEEN ABLE TO DISCOVER THE REASONS THAT HIS ESTIMATES FOR LEVELIZED COST FOR KANSAS WIND WERE SO LOW?

A. Yes, I have. I looked at three major areas: 1) Implicit Capacity Costs); 2) Annual Expenses; and 3) Credits used to offset costs. The following table summarizes my findings.

Berry's Calculations for Kansas Wind

Revenue Requirements	**$/MWh**
Implicit Capacity Cost	$38.57
Expenses	$11.90
Total Revenue Requirement	**$50.47**

Credits	**$/MWh**
Capacity Revenues	$7.89
Production Tax Credits	$27.49
Berry's LCOE ($/MWh)	**$15.08**

While I found many issues with Mr. Berry's calculations of implicit capacity costs as well as for annual expenses, I discovered that the primary reason for his low levelized cost for Kansas wind comes from the credits he used to offset costs. These levelized costs do not include the costs of the DC Transmission project, nor do they take into account losses on that line.

Q. WHAT DO YOU MEAN BY CAPACITY COSTS?

A. For Kansas Wind capacity costs include the return of and on investment along with income taxes, or sometimes called "pre-tax" return on investment.[1] Levelized cost analysis calculates the return of investment using annual, straight-line depreciation. The return on investment is what is required to cover the annual interest expense as well as annual rate of return on equity including income taxes. Using the DOE 2012 WTMR's interior region's average installed cost for a wind turbine of $1,760/kW-yr (at page 36) and Mr. Berry's rates for return on investment, interest, discount and income taxes, I estimated the levelized capacity costs for Kansas Wind to be $34.63/MWh, which is essentially the same cost as those used by the SPP. Notice that the EIA estimate of $70.30/MWh (in previous table on page 2) is based on an assumed 34% capacity factor. Adjusting the capacity factor to 50% reduces the EIA estimate to $47.80/MWh. A major reason for EIA's higher levelized cost is the higher project cost per kW-year at the time of the 2013 EIA report.

Q. HOW DOES THIS LEVELIZED COST FOR THE RETURN OF AND ON INVESTMENT COMPARE TO MR. BERRY'S CALCULATIONS?

A. Subtracting out his levelized costs for revenue credits and expenses, Mr. Berry's residual for what would be implicit capacity costs is $38.57/MWh. Even though Mr. Berry's estimate is higher than mine, in Mr. Berry's work papers I found that he had used $1,750/kW-yr and had

[1] Some analysts include property taxes as capacity costs. For Kansas wind, there are no property taxes.

deflated the estimated cost one year, lowering the investment cost to $1,707/kW-yr. In addition Mr. Berry used a wind capacity factor of 55%, which he considered mid-range, even though his survey of potential suppliers averaged 52% and the DOE 2012 WTMR on Figure 31 at page 48 shows the highest 2012 capacity factor in the interior region to be 50%. I used a wind capacity factor of 50%, which is representative of a mid-to-high range estimate for the western Kansas region. A mid-range capacity factor for Kansas Wind would be lower than the 50% level used in my analysis; perhaps as low as 45%. These capacity factors are measured at the generators, not at the delivery point. Thus, losses need to be taken into account. Mr. Berry's calculation of $38.57/MWh does not include transmission losses.

Q. WHAT ROLE DOES THE CAPACITY FACTOR PLAY IN THE CALCULATION OF A LEVELIZED COST FOR A RESOURCE?

A. Levelized cost is simply a constant per year revenue requirement whose present value is equal to the present value of estimated revenue requirements over the life of an asset. In order to convert this dollar value to dollars per MWh, the levelized cost is divided by the MWh expected to be produced by the generation asset each year. In the case of wind, the capacity factor is equal to the expected MWh produced in a typical year divided by the maximum MWh that could be produced if the wind was generating at the full capacity of the plant every hour of the year.

Levelized costs can easily be calculated on a 1 MW basis. Since the capacity factor times 8,760 hours is the MWh produced by a generator having 1 MW of capacity, levelized cost can be divided by the capacity factor times 8,760 hours to convert to $/MWh. If two alternatives have the same levelized costs in dollars (for example two wind farms), the alternative having the higher capacity factor (for example more consistent wind compared to less consistent wind) will have the lower levelized cost per MWh.

2. <u>LEVELIZED EXPENSES</u>

Q. WHAT DID MR. BERRY INCLUDE IN ANNUAL EXPENSE FOR KANSAS WIND?

A. There is no property tax and no fuel expense for Kansas wind. Mr. Berry used an estimate of \$7.50/MWh which he determined from the 2012 Wind Technologies Market Report. To this Mr. Berry added a 2.5% inflation factor to arrive at a starting 2019 value of \$8.70/MWh. He then adds to the 2.5% inflation factor plus a 1% escalation factor for a 3.5% year-to-year increase. Based on these assumptions, Mr. Berry estimates a levelized expense of \$11.90/MWh.

Q. DO YOU AGREE WITH MR. BERRY'S APPROACH FOR ESTIMATING ANNUAL EXPENSE FOR KANSAS WIND?

A. No, I do not. I do not agree with the use of an inflation factor and the combination of an inflation factor and escalation factor to arrive at nominal cost for annual expense.

Q. WHY IS IT INCORRECT TO USE INFLATION FACTORS TO INCREASE YEAR-TO YEAR COSTS OVER THE LIFE OF AN ASSET IN THE CALCULATION OF LEVELIZED COSTS?

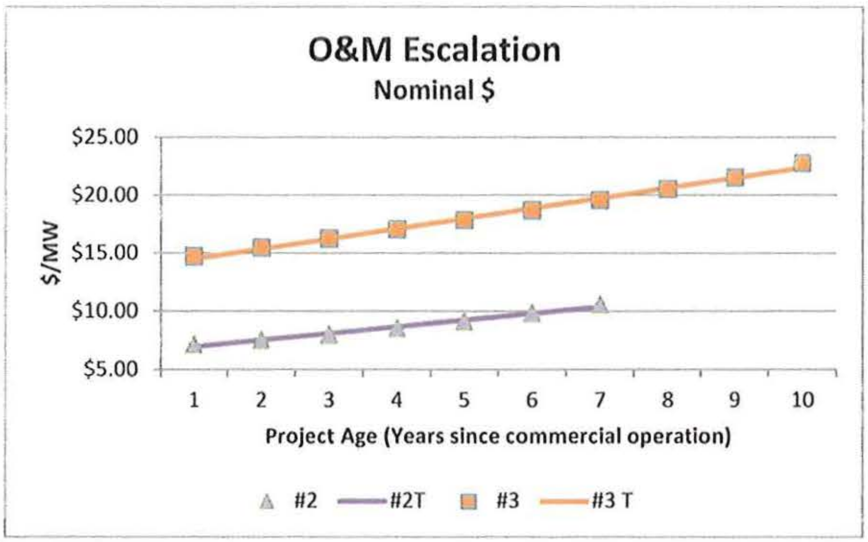
A. An inflation factor is used to account for the purchasing power of a dollar in the purchase of a bundle of goods. For example the Consumer Price Index (CPI) is used for calculating the purchasing power of retail customers and the Wholesale Price Index (WPI) is used for calculating the purchasing power of wholesale customers. The Gross Domestic Product (GDP) price index is typically used in studies by the Energy Information Agency (EIA) that produces energy forecasts for the Department of Energy. No matter which price index is used, the inflation rate from year x to year y is calculated as the index in year y divided by the index in year x. Forecast of costs are typically done in nominal dollars – the actual costs at the time the expenditure is made. In order to convert these forecasts to real dollars in year x, the nominal dollars in year y are divided by the inflation factor from year x to year y. The result is a forecast based on the purchasing power in year x.

The data reported in the DOE 2012 WTMR on median annual O&M costs for wind generation is stated to be in 2012 $/MWh. This means that the data reported before 2012 was factored up for inflation from the date the data was reported to the year 2012 using a price index. The data was then separated into three groups (1998-2004; 2005-2008 & 2009-2011) depending on the date of commercial operation. For each of the three groups, median (middle) $/MWh of expense were calculated for each of the years since the wind farm's commercial operation date. The data was then analyzed for upward trends over the years since commercial operation.

Apparently, Mr. Berry believed that to convert these trends to nominal dollar he should apply a forecasted inflation rate for each subsequent year, but this is not the correct way to get from real dollars to nominal dollars. Instead, the real dollar data should first be converted back to nominal dollars and then the trends analyzed to determine if the data shows an escalation of costs in nominal dollars.

Q. DID YOU ANALYZE THE DATA FOR COST ESCALATION IN NOMINAL DOLLARS?

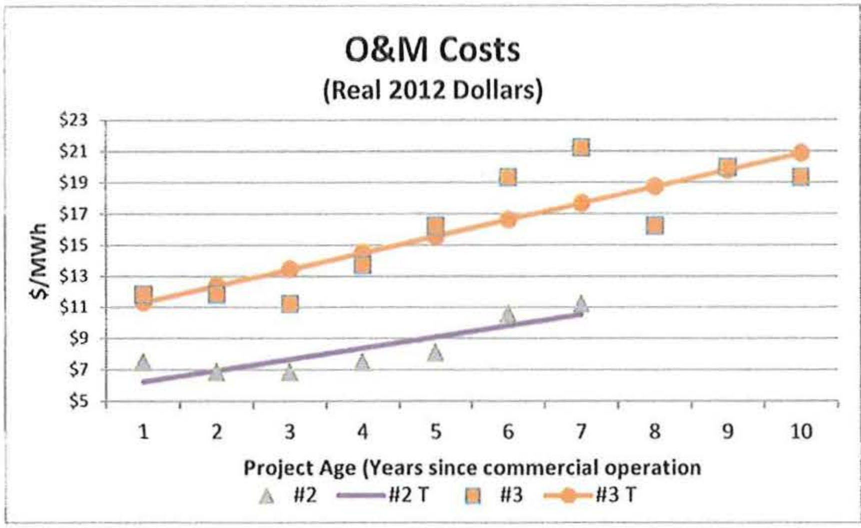
A. Yes, I did. The data had been sorted into three groups according to year of commercial operation: 1) 2009-2011; 2) 2005-2008; and 3) 1996-2004. I used the GDP price index to convert the data from real to nominal values, and then performed a linear trend analysis for each group. Group 1 only has three observations, and is likely to be of little value in determining trends. The first three observations from Group 2 showed slightly lower costs, but were in the same range as Group 1. Group 3 (the older wind generators) showed significantly higher costs than either Group 1 or 2, and also showed a higher level of cost escalation. The following graph shows the trend results for Groups 2 and 3.



Notice that both groups fit a dollar per year escalation very well. However, since Group 2 tracks better with the more recent data, having a lower dollar level and a lower dollar per year escalation, I used the trend line values from Group 2 as the best estimate for the most recently built wind farms.

Q. DID YOU PERFORM A SIMILAR ANALYSIS USING 2012 REAL DATA?

A. Yes, I did. As shown in the following graph, the trend lines for the real data do not provide as good a fit as the trend lines for the nominal data. However, after calculating the trends for real, I compared them to the trends for the nominal.



The real data shows a higher level of escalation than the nominal data. The following table compares the trend lines for real vs. nominal for Groups 2 and 3.

Trends	Group 2		Group 3	
	Real	Nominal	Real	Nominal
Year 1	$6.25	$7.00	$11.35	$14.53
Year 25	$23.39	$20.65	$36.81	$35.68
Yr to Yr Inc	$0.71	$0.57	$1.06	$0.88
Avg Growth Rate	5.65%	4.61%	5.02%	3.82%

Notice the lower starting values at year 1 for the real trends, but the higher ending values at year 25, resulting in a higher year-to-year increase as well as a higher average 25 year escalation rate for the real data compared to the nominal data.

Q. USING THE TREND LINE FOR NOMINAL COSTS FROM GROUP 2, WHAT ESTIMATE OF LEVELIZED O&M COST DID YOU CALCULATE FOR WIND?

A. Using the trend line for nominal O&M expenses I calculated a levelized O&M expense estimate over the 25 year life of $11.73/MWh. While we differed in approach, this estimate is comparable to Mr. Berry's estimate of $11.90/MWh.

Q. TO THIS POINT IN THE ANALYSIS WHAT IS YOUR ESTIMATE OF LEVELIZED WIND COSTS COMPARED TO MR. BERRY?

A. I estimate the levelized cost of Kansas wind to be $46.35/MWh, and Mr. Berry estimates the levelized costs to be $50.47/MWh. In order for Mr. Berry's final estimate to be $15/MWh, he must show $35/MWh in credits to offset these costs.

3. <u>REVENUE REQUIREMENT CREDITS VS CHARGES FOR KANSAS WIND</u>

Q. WHAT CREDITS DID MR. BERRY INCLUDE IN HIS LEVELIZED COST ANALYSIS?

A. Mr. Berry included a Production Tax Credit and a Capacity Credit for the accredited capacity for resource adequacy (MW available at times of summer peak) of the Kansas Wind Farms.

Q. WHAT IS A PRODUCTION TAX CREDIT?

A. The federal government allows a $23/MWh tax credit for MWh produced over the first 10 years of operations for wind farms that began construction prior to December 31, 2013.

Q. WHAT DID MR. BERRY ESTIMATE THE LEVELIZED LEVEL TO BE FOR THE PRODUCTION TAX CREDIT?

A. Mr. Berry estimated a levelized production tax credit of $27.49/MWh over the first 10 years of the 25 year life of the Kansas wind farms. Mr. Berry applied the inflation rate as if the federal law would grant wind farms an inflation factor of 2.5% per year to the production tax credit.

Q. WHAT IS YOUR ESTIMATE OF THE PRODUCTION TAX CREDIT?

A. I used the EIA inflation factor of 1.55% to arrive at $25/MWh as nominal dollars in 2019, and using the EIA inflation factor of 1.65% over the next ten years, estimated the levelized production tax credit to be $16.51/MWh. Along with the availability of production tax credits for renewable energy, the future rate of inflation is a major uncertainty in calculating the production tax credit.

Q. DO YOU AGREE THAT THE PRODUCTION TAX CREDIT FOR RENEWABLE ENERGY WILL APPLY TO THE KANSAS WIND FARMS THAT CONNECT TO THE DC TRANSMISSION PROJECT IN 2019?

A. No, I do not. It is impossible to know what congress will enact in the future with respect to renewable energy. To meet current law, these farms would have had to have started construction prior to December 31 of last year. In order for this to make sense, these farms will have to interconnect to the SPP transmission system in order to generate revenues to cover their investment until 2019. These interconnection costs are not insignificant (in the order of $300/kW). I would estimate that wind farms already interconnected to SPP would not be willing to switch interconnections to the DC Transmission project, so that essentially the wind farms interconnecting to the DC Transmission project would primarily be those constructed just prior to 2019 and would not be eligible for the existing production tax credit.

Congress has yet to extend the production tax credits for wind in the 2014 session. The last extension in 2013 simply changed the existing requirement from "fully operational" to "under construction" by December 31, 2013. Thus, it would not seem reasonable to assume production tax credits will be extended past what is allowed by current legislation.

Q. WHAT CAPACITY CREDIT WAS CALCULATED BY MR. BERRY?

A. Mr. Berry assumed accredited capacity equal to 17.05% of name plate capacity for Kansas wind, and valued this capacity at the cost of a combustion turbine at $957/kw. As with variable O&M and production tax credits, Mr. Berry not only inflated the cost of the combustion turbine to 2019 dollar, but used the inflation rate as an escalation rate over the 25 year life of the wind farm. This resulted in a levelized capacity credit of $7.89/MWh.

When Mr. Berry's levelized production tax credit and capacity credit are added, the result is a total credit against cost of $35.39/MWh. When this is subtracted from his levelized cost estimate of $50.47/MWh, the result is a levelized cost for Kansas wind of $15.08/MWh

Q. DO YOU AGREE WITH MR. BERRY'S CAPACITY CREDIT?

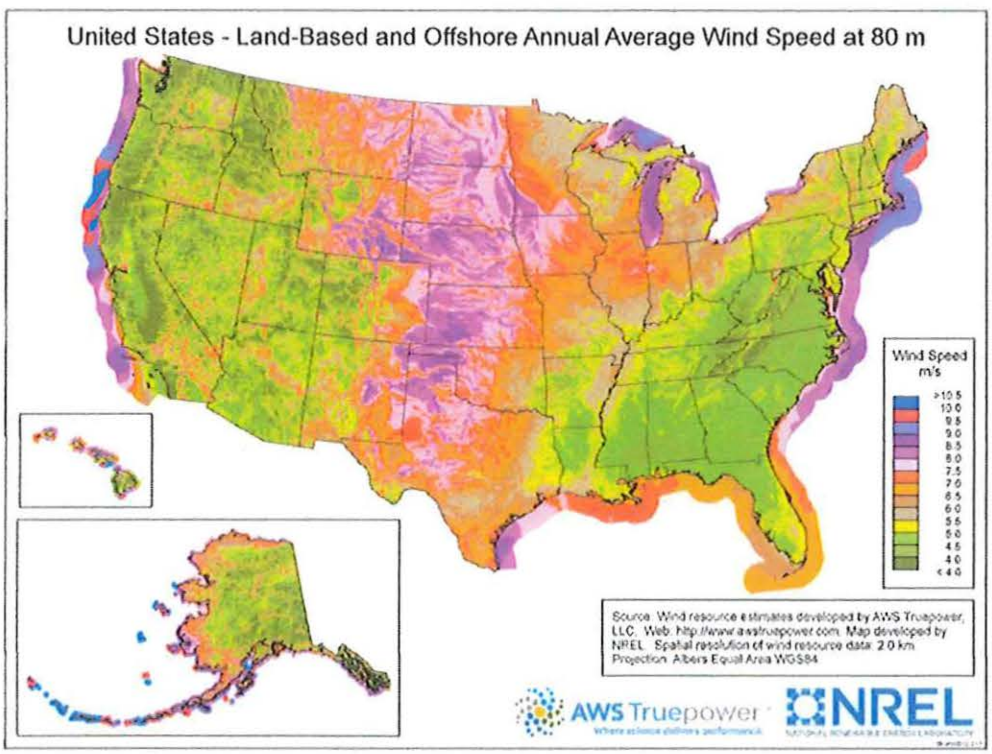
A. No, I do not. In addition to this not being included in a standard calculation of levelized costs, because of the risk involved in being able to sell the capacity in a capacity market subtracting capacity credits is not the way a wind farm would sell energy. Similarly, if a utility were considering purchasing a wind farm in Kansas, subtracting the capacity value is not the treatment that it would use in making a decision. In addition, Mr. Berry estimate of 17.05% accredited (unforced) capacity available during the summer peak period was not calculated using any known standard for determining accredited capacity.

Q. WHAT IS THE STANDARD WAY ACCREDITED CAPACITY DIFFERENCE BETWEEN WIND FARMS AND NON-RENEWABLE GENERATION IS TAKEN INTO ACCOUNT?

A. To compare two generation resources, the accredited capacity of the resource with the lower percentage of accredited capacity is subtracted from the resource with the higher percentage of accredited capacity. For example, a combined cycle plant with accredited (unforced) capacity of 93% and Kansas wind having accredited (unforced) capacity of 14.5% would result in a difference of 78.5% in accredited capacity. In order to compare the costs of these two resources, the cost of additional 78.5% of accredited capacity would need to be added to the cost of the Kansas wind. Including the capital and fixed O&M costs for a combustion turbine, I estimate this added capacity cost to be $19.30/MWh. Adding this to the cost of Kansas Wind before production tax credits gives a total levelized cost of $65.65/MWh.

Q. WHY DID YOU USE 14.5% ACCREDITED CAPACITY FOR KANSAS WIND INSTEAD OF 17.05% USED BY MR. BERRY?

A. Mr. Berry calculated the 17.05% by multiplying the Midwest ISO's accredited capacity for Missouri Wind of 9.3% by ratio of Kansas wind capacity factor of 55% to the Missouri wind capacity factor of 30%. In order for this calculation to be valid, this ratio of 1.83 would have to apply during the peak hours of the summer when accredited capacity is determined. The problem is that during the hot peak hours, wind tends to reduce significantly in both high and low wind areas, but not in proportion to the average of wind production throughout the year. The following map shows wind speeds in the United States.



I used 14.5% because it is the average of the highest capacity factor region in the Dakotas and western Minnesota (15.8%) with the Iowa region (13.7%) in the Midwest ISO. I chose these two regions because the highest capacity factor region is in the northwest portion of the Midwest ISO, has similar average annual wind speeds, but lower summer temperatures than western Kansas. The wind in northwest Iowa also has the same annual average wind speeds as western Kansas. It should also be noted that these accredited capacity values for the summer peak were measured by the Midwest ISO in 2012 which had the highest accredited capacity values over the last three years. Even in this case, these accredited capacities for wind did not reach 17%.

4. TRANSMISSION COSTS AND LOSSES FOR KANSAS WIND

Q. WHAT OTHER FACTORS NEED TO BE TAKEN INTO ACCOUNT REGARDING THE LEVELIZED COST OF WESTERN KANSAS WIND VIA THE DC TRANSMISSION PROJECT?

A. Transmission costs and transmission losses need to be taken into account. The reason for this is that a proper comparison of western Kansas wind generation to other generation resources that can locate in Ameren Missouri's service territory require the wind energy from Kansas to be delivered to the Ameren Missouri service territory. This requires the inclusion of the transmission costs and losses needed to deliver the wind generation to Ameren Missouri's service territory, but does not include transmission costs and losses to deliver from generation located in Ameren Missouri's service territory to Ameren Missouri's load, as these costs would be similar for all resource alternatives being considered.

Q. WHAT ARE THE TRANSMISSION COSTS FOR THE DC TRANSMISSION PROJECT?

A. In his direct testimony, Mr. Berry estimates these costs to be in the range of $15/MWh to $20/MWh. In his worksheet, Mr. Berry calculates a levelized cost for the DC Transmission project to be $18.47/MWh. Since these are preliminary estimates, they are likely to be low. The SPP has found preliminary cost estimates for transmission projects to be 30% lower than actual costs. This might be included in Mr. Berry's range (i.e., \$20/MWh = 1.33 * \$15/MWh).

However using Mr. Berry's rate calculation for the DC Transmission project of \$89.07/kW-yr results in a levelized cost of \$17/MWh, and adding 30% results in a levelized cost of \$22/MWh. This estimate is slightly higher than the high end of Mr. Berry's estimate range because I am using a capacity factor of 50% instead of the 55% that he used. The same result can be obtained by multiplying Mr. Berry's estimated range by the ratio of 0.55/0.5 = 1.1; i.e., a 10% increase in cost due to a lower capacity factor would change \$20/MWh to \$22/MWh. I believe \$22/MWh is a reasonable estimate to use. Adding \$22/MWh for transmission to \$65.65/MWh for generation, results in a levelized cost for Kansas Wind of \$87.65/MWh.

Q. WHAT ARE THE TRANSMISSION LOSSES FOR THE GRAIN BELT DC TRANSMISSION PROJECT?

A. Mr. Berry estimates these to be 5%. Thus, actual delivered energy is 5% lower than generated energy. This means that all cost estimates need to be divided by 0.95 to accurately reflect the cost of delivered energy. Accounting for losses adds \$4.61/MWh, bringing the total cost for western Kansas Wind delivered into Ameren Missouri's service territory to \$92.26/MWh.

D. LEVELIZED COST OF COMBINED-CYCLE GENERATION

1. DIFFERENCE IN LEVELIZED COST

Q. DID MR. BERRY CALCULATE THE LEVELIZED COST FOR A COMBINED CYCLE GENERATION ALTERNATIVE?

A. Yes, he provided those calculations in his work papers.

Q. DID YOU FIND THE SAME OVERALL PROBLEMS WITH MR. BERRY'S METHOD OF CALCULATING LEVELIZED COSTS FOR KANSAS WIND?

A. Yes, I did. Mr. Berry used the same methods for all of his levelized cost calculations. In addition, I found a calculation error in his Net Present Value calculation of total expenses. After correcting for this error, the following table shows the component of Mr. Berry's calculation:

Revenue Requirements	$/MWh
Implicit Capacity Cost	$28.54
Expenses	$89.20
Total Revenue Requirement	**$117.74**
Credits	**$/MWh**
Capacity Revenues	$27.98
Production Tax Credits	$0.00
Berry's LCOE ($/MWh)	**$89.76**

Q. HAVE YOU CALCULATED THE LEVELIZED COST FOR A COMBINED CYCLE GENERATION?

A. Yes, I have. There are four components to this calculation.

Combined Cycle	$/MWh-Yr
Capacity Costs	$13.48
O&M Costs	$5.45
Fuel Expense	$54.44
CO2 Costs	$12.60
Total Costs	$85.97

Mr. Berry's capacity costs are $15/MWh higher than my calculations, and adding up all of the expenses gives $85.97/MWh compared to Mr. Berry's estimate of $117.74/MWh before revenue credits; a difference of over $21/MWh.

Q. WHY ARE CO2 COSTS INCLUDED IN YOUR CALCULATIONS?

A. Currently CO_2 costs are **<u>not</u>** being charged to fossil fuel generation. This will likely change with the new regulations being proposed by the Environmental Protection Agency (EPA). and therefore CO_2 cost is a risk factor that should be included in making a risk comparison.

Q. HOW DID MR. BERRY ASSESS THE RISK OF CO2 COSTS?

A. Mr. Berry uses an estimated cost of $15/ton as a mid-range projection of CO_2 costs. He inflates this cost over the 30 year life of the combined cycle alternative and derives a levelized estimate of just over $20/MWh.

Q. IN YOUR OPINION IS THIS A PROPER RISK ASSESSMENT FOR CO2 COSTS?

A. No, it is not. First, at $15/ton I calculate a levelized cost of $12.60/MWh. When this is added to the levelized cost for the combined cycle unit, its cost goes up to $85.97/MWh, which is still below $92.26/MWh (Kansas Wind without production tax credits). Second, a lower CO_2 price of $10/ton results in a levelized cost of $8.40/MWh and lowers the combined cycle levelized cost to $81.77/MWh, which is well below the Kansas Wind levelized cost. Third, a higher CO_2 price of $25/ton results in a levelized cost of $19.44/MWh, and raises the levelized cost for combined cycle to $92.82/MWh, which takes the Combined Cycle levelized cost just above the levelized cost for Kansas wind without the production tax credit. Thus the economic viability of western Kansas wind compared to combined cycle generation rests on what is estimated as a high charge for CO_2 emissions for combined cycle generation.

Q. EVEN WHEN USING THE HIGH CO2 COST WHY ARE YOUR LEVELIZED COSTS SIGNIFICANTLY LOWER THAN MR. BERRY'S ESTIMATE?

A. A major difference appears in the calculation of capacity costs for combined cycle generation. My levelized cost estimate for return on and of investment is $13.48/MWh compared to Mr. Berry's implicit estimate of $28.54/MWh. In order to determine the differences in expenses, I had to decompose Mr. Berry's Total Expense into O&M Expense, Fuel Expense and CO2 Expense.

Q. WHAT DID YOUR ANALYSIS OF EXPENSES FOR COMBINED CYCLE GENERATION SHOW AS THE AREAS OF DIFFERENCE?

A. The following table shows the differences in levelized costs for the three major cost components for combined cycle generation.

Expense Components	Levelized $/MWh		
	Proctor	Berry	Diff
O&M Expense	$5.45	$8.53	$3.07
Fuel	$54.44	$60.60	$6.16
CO2 Mid	$12.60	$20.07	$7.48
Total Expenses	$72.49	$89.20	$16.71

I have previously discussed the differences in the calculation of CO2 costs. However the differences in Fuel and O&M Expenses are also significant. The reason Mr. Berry's estimates in these two categories are higher is he has improperly used the inflation rate to escalate these costs over the life of the asset.

I did not escalate the O&M Expenses (fixed and variable), as there was no forecast evidence to support an increase in nominal level for these cost. For fuel I used the EIA's projection of natural gas prices for electric plant fuel and since these were reported in real dollars. I did have to convert to nominal dollars. I did so using the EIA's inflation factors which it used to deflate their forecast in nominal dollars. The EIA's inflation factors, averaging 1.66%/year, were significantly lower than Mr. Berry's assumed 2.5% per year. This difference in escalation rates accounts for the difference in fuel expense.

Q. WHAT ABOUT THE ARGUMENT THAT NOMINAL EXPENSE WILL INCREASE WITH THE RATE OF INFLATION?

A. Assuming that this is a possibility, when I applied the EIA's average inflation rates to the fixed and variable O&M expenses, they increased by $1.06/MWh. This accounts for approximately 1/3 of the difference between my O&M estimates and those of Mr. Berry who used a 2.5% per year inflation rate.

Q. IN SUMMARY, HOW DOES KANSAS WIND + DC TRANSMISSION COMPARE TO COMBINED CYCLE GENERATION?

A. My rebuttal testimony to this point has presented a step-by-step comparison of my calculations to those of Mr. Berry. The following table shows the components of my calculations for Kansas Wind + DC transmission, Missouri Wind, which will be discussed in a following section of my rebuttal testimony, and Combined Cycle generation.

Levelized Cost Components for Geneation Alternatives

Alternatives	Capacity Costs		O&M Costs		Fossil Fuel		Capacity Adder	Trans Adder	Loss Adder	**Total**
	Returns	Prop TX	Fixed	Var	Fuel Cost	CO2				
Kansas Wind	$34.63	$0.00	$0.00	$11.73	$0.00	$0.00	$19.30	$22.00	$4.61	$92.26
Missouri Wind	$46.17	$0.00	$0.00	$11.73	$0.00	$0.00	$40.84	$0.00	$0.00	$98.73
Combined Cycle	$12.19	$1.29	$2.08	$3.37	$54.44	$12.60	$0.00	$0.00	$0.00	$85.97

These levelized costs show that Combined Cycle is the most cost-effective generation alternative for meeting Ameren Missouri's need for base-load generation. However, these comparisons are based on expected forecasts and do not include an analysis of various risk factors.

2. <u>RISK FACTORS IN COMPARING WIND TO COMBINED CYCLE</u>

Q. WHAT ARE THE RISK FACTORS THAT NEED TO BE EVALUATED IN COMPARING KANSAS WIND TO COMBINED CYCLE GENERATION?

A. The major risk factors are related to federal government policy including: 1) Will the congress continue to promote renewable generation by providing a production tax credit; and 2) Will proposed CO_2 rules by the EPA be put in place, and if so, what will be the cost of CO_2 allowances?

Q. HOW SHOULD THE MISSOURI COMMISSION TREAT THESE RISK FACTORS IN ITS EVALUATION OF THE ECONOMIC VIABILITY OF KANSAS WIND VIA THE CLEAN LINE DC TRANSMISSION PROJECT?

A. The Missouri Commission has three basic alternatives:

1. **Business as Usual** – Use only the government policies currently in effect.
2. **Likely Changes** – Use policies the government is currently working on that favor wind.
3. **Aggressive Changes** – Use policies the government may implement in favor of wind.

For Business as Usual, the CO_2 cost would be removed from the combined cycle alternative and production tax credits for wind would not be included. This approach would set combined cycle levelized costs at $73.37/MWh compared to Kansas Wind at $92.26/MWh; a difference of $18.89/MWh.

For Likely Changes, the CO_2 mid-range costs would be added to the cost of the combined cycle costs increasing those costs to $85.97/MWh; still $6.29/MWh cheaper than Kansas Wind, and this difference is greater than the $5/MWh difference allowed by Missouri legislation for requiring 15% of generation coming from renewable resources.

For Aggressive Changes, the CO_2 high-range costs would be included for combined cycle costs, increase those costs to $92.82/MWh, and the Production Tax Credits for wind would be included, decreasing Kansas wind cost to $76.57/MWh. Thus, aggressive federal policy would lead to the Kansas Wind via the DC Transmission project to be economically viable.

Obviously, various combinations of these three basic alternatives can also be considered. However, in two out of three of the basic alternatives, Kansas Wind via the DC Transmission project is not competitive with natural gas fired combined cycle generation.

Q. ARE THERE OTHER RISK FACTORS THE MISSOURI COMMISSION COULD TAKE INTO ACCOUNT?

A. Of course all of the costs are estimates and forecasts that are uncertain. On the Combined Cycle side the forecasted price of natural gas is one of the most significant in terms of uncertainty. On the Kansas wind side the capacity factor used for Kansas wind generation is also subject to uncertainty. I see these uncertainties as offsetting risks in comparing the two alternatives.

E. KANSAS WIND + DC TRANSMISSION VS. MIDWEST ISO WIND

Q. WHAT IS THE BASIS FOR THE NEED RELATED TO WIND IN MISSOURI?

A. Missouri legislation requires 15% of generation to come from renewable resources as long as the cost of renewable energy does not exceed $5/MWh from non-renewable resources.

Q. DOES MR. BERRY'S TESTIMONY SHOW THERE IS A NEED FOR KANSAS WIND + DC TRANSMISSION?

A. No, it does not. Mr. Berry's testimony shows that the Kansas Wind project is less costly than a Missouri Wind project having a much lower capacity factor of 30%. In addition, Mr. Berry found renewable solar energy as being more costly. While I found higher levelized costs for Kansas Wind + DC Transmission and Missouri Wind, I came to the same conclusion as Mr.

Berry. However, using low capacity factor wind as the only wind alternative does not show a need for the Kansas Wind project.

Q. WHAT OTHER WIND ALTERNATIVES SHOULD MR. BERRY HAVE EVALUATED IN SHOWING A NEED FOR THE KANSAS WIND PROJECT?

A. Mr. Berry should have also evaluated wind coming from high capacity factor regions within the Midwest ISO. Moreover, if Ameren Missouri can meet its renewable energy requirements from these alternatives at a lower cost than from the Kansas Wind + DC Transmission, then there is no need for that project.

Q. HAVE YOU PERFORMED AN ANALYSIS OF LEVELIZED COSTS FOR WIND COMING FROM THE MIDWEST ISO?

A. Yes, I have. First, the wind map of the United States shows the northwest region of Iowa and the eastern region of South Dakota have higher capacity factor wind than what can be found in the best wind regions of Missouri. Second, I calculated the levelized costs for wind generation (including capacity adders) at various capacity factors from 30% up to 50%. By adding $5/MWh to the levelized cost of combined cycle at $85.97/MWh, wind would have to be under $91/MWh to meet the need for renewable energy in Missouri.

The following table shows that wind with a capacity factor as low as 35% would meet this need. This comparison only includes the cost of generation, not any added cost for AC transmission service, transmission losses, or any production tax credits. Notice also that Missouri wind is treated differently as it gets a 25% added renewable energy credit. Comparing Missouri wind to the wind at 30% capacity factor, the capacity costs are lower by 1/1.25, but the capacity adder is higher by 1.25. While Missouri wind is slightly less costly than non-Missouri wind at the same capacity factor, it still will not meet the $5/MWh limit when compared to combined cycle generation.

Levelized Costs with Capacity Adders
for Alternative Capacity Factors

Capacity Factors	Capacity Costs	O&M Expense	Levelized Costs	Capacity Adder	Total
30%	$57.71	$11.73	$69.44	$32.67	$102.11
MO 30%	$46.17	$11.73	$57.89	$40.84	$98.73
35%	$49.47	$11.73	$61.19	$27.89	$89.09
40%	$43.28	$11.73	$55.01	$24.31	$79.32
45%	$38.47	$11.73	$50.20	$21.53	$71.72
50%	$34.63	$11.73	$46.35	$19.30	$65.65

Q. WHAT ADDITIONAL COSTS NEED TO BE CONSIDERED WHEN EVALUATING MIDWEST ISO WIND?

A. There are two alternatives to be considered for Midwest ISO wind: 1) Energy-Only resource; and 2) Energy and Capacity resource. If Ameren Missouri were to take Midwest ISO wind as an Energy-Only resource, then it would have to add capacity in the form of additional combustion turbines. If, instead, Ameren Missouri were to take Midwest ISO wind as an Energy and Capacity resource, then it would have to add firm transmission service for the delivery of that capacity to its load.

1. <u>ENERGY-ONLY RESOURCE</u>

Q. WHAT IS AN ENERGY-ONLY RESOURCE?

A. An energy-only resource is one for which the utility foregoes the capacity of that resource and does not take firm transmission service.

Q. WHAT IS THE ADDED COST IF WIND LOCATED WITH THE MIDWEST ISO IS TAKEN BY AMEREN MISSOURI AS AN ENERGY-ONLY RESOURCE?

A. In order to compare energy-only wind resources to the Kansas Wind + DC Transmission, both alternatives need to be evaluated in terms of equivalent generation capacity levels. To make this calculation consistent with comparisons already made to Combined Cycle generation, the energy-only wind resource would need to add the full capacity of the Combined Cycle unit but at the cost of a Combustion Turbine unit. The following table shows this comparison for a range of capacity factors for energy only wind resources located within the Midwest ISO.

Levelized Costs for Energy Only from Wind and Capacity from Combustion Turbines

Capacity Factors	Capacity Costs	O&M Expense	Levelized Costs	Capacity Adder	Total	Difference
30%	$57.71	$11.73	$69.44	$36.07	$105.51	($17.86)
MO 30%	$46.17	$11.73	$57.89	$45.09	$102.99	($15.34)
35%	$49.47	$11.73	$61.19	$31.22	$92.41	($4.76)
40%	$43.28	$11.73	$55.01	$27.58	$82.58	$5.06
45%	$38.47	$11.73	$50.20	$24.74	$74.94	$12.71
50%	$34.63	$11.73	$46.35	$22.48	$68.83	$18.82
Kansas DC	Does Not Include Losses				$87.65	

Q. WHAT IS THE SIGNIFICANCE OF THE DIFFERENCES SHOWN BETWEEN KANSAS WIND + DC TRANSMISSION AND ENERGY-ONLY WIND LOCATED IN THE MIDWEST ISO?

A. First, a capacity factor above 35% is needed in order for energy-only wind located in the Midwest ISO to be competitive with Kansas Wind + DC Transmission. Second, an Energy-Only resource is not eligible for receiving an allocation of Financial Transmission Rights. This means that Ameren Missouri would receive the locational marginal price (LMP) for the energy from the energy-only resource at the location of that resource, and would pay the LMP at the locations of their loads. The difference between these two prices times the energy from the energy-only resource (the congestion costs) would be paid by Ameren Missouri to the Midwest ISO if the price at the generator is below the price at the load. The previous table shows the dollars per MWh available to Ameren Missouri for the average annual differences between the prices at the energy only wind resource and its load.

Q. ARE THE DIFFERENCES FROM $5/MWh TO JUST UNDER $19/MWh SUFFICIENT TO COVER POTENTIAL CONGESTION COSTS?

A. While congestion costs are very specific to the locations of the generator and load, an analysis of the clearing prices for the Midwest ISO's FTR markets show a very high probability that the differences are sufficient to cover congestion costs. Seasonal FTRs are bought and sold for peak and off-peak periods. The following table shows the results from the 2013 markets over all four seasons. This table gives the number of FTRs sold in 2013 that are between the $/MWh shown in the first column for each corresponding capacity factor.

Annual 2013 FTR Results

$/MWh	50% CF	45% CF	40% CF
$18.82	30	38	45
$12.71	49	56	90
$5.06	594	685	744
$2.50	910	983	1,062
$0.00	37,358	37,179	37,000
Total	38,941	38,941	38,941
% Below	**99.92%**	**99.76%**	**97.74%**

The cells with the reddish hue show the number sold that would not have been covered by the cost difference between Kansas Wind + DC Transmission and Energy-Only wind from the Midwest ISO. The bottom row shows the percent of FTRs for which the cost differences would more than cover the cost of the FTRs. The worst case scenario is 40% capacity factor wind which has the lowest percentage of cases covered; yet, even in that case, the percentage of FTRs transacted that would be covered by the cost difference is just under 98%.

Q. DOES THIS PROVIDE SUFFICIENT EVIDENCE THAT KANSAS WIND IS NOT LIKELY TO BE COMPETITIVE WITH WIND LOCATED IN THE MIDWEST ISO?

A. From an economic perspective, yes it does. However, if Ameren Missouri is required to take firm transmission service from its wind resources, then one must consider the added cost of transmission rather than the added cost of generation capacity.

2. <u>AC FIRM TRANSMISSION SERVICE</u>

Q. IN THE MIDWEST ISO IS THERE AN ADDED TRANSMISSION COST FOR RESOURCES LOCATED OUTSIDE THE UTILITY'S TRANSMISSION ZONE?

A. If the utility wants firm transmission service from any resource, it is possible that some additional transmission charges could be added to the utility. Those charges will vary by location, and this is important as resources located outside the utility's transmission zone are likely to have larger additional transmission charges than those located with the utility's transmission zone.

Q. DO YOU HAVE AN ESTIMATE OF ADDED TRANSMISSION CHARGES FOR AC WIND ALTERNATIVES?

A. Because firm transmission service is resource and load specific, it is not possible to provide a definitive estimate. However, I can provide information about transmission planning that is useful for purposes of estimating a reasonable range for these added transmission costs.

AC transmission service is provided in the Midwest ISO through zonal and region-wide rates. These rates collect the annual revenue requirements for the existing transmission system in each year. As transmission is added, the annual revenue requirements for the new investment will be added to those of the existing system. Therefore, it is important to understand how investment in new transmission occurs.

The Midwest ISO performs transmission planning on a regular basis. In order to simplify generic terms are used to describe the transmission planning process (various RTO's use different technical terms).

1. **Generation Interconnection:** Generation owners request to be connected to the transmission system, and the RTO determines if upgrades are needed to maintain the reliability of the transmission system. The Generators must pay for these upgrades upfront, but are eligible for refunds over time.
2. **Resource and Load Integration:** With the addition of new generation resources and new load, the RTO determines what upgrades are needed to maintain reliability of the transmission system, meet public policy needs or improve the efficiency of the regional markets.
3. **Transmission Service Requests:** Transmission customers request additional firm transmission service (point-to-point or network service), and the RTO determines if upgrades are needed to maintain the reliability of the transmission system. The transmission customers are directly assigned the cost of these upgrades, and in some RTOs are eligible for refunds as these upgrades are used to meet the transmission needs of future transmission service requests.

Q. HOW DO THESE THREE PLANNING PROCEDURES APPLY TO THE QUESTION OF ADDED AC TRANSMISSION COST FOR WIND LOCATED OUTSIDE OF AMEREN MISSOURI'S TRANSMISSION ZONE?

A. First, it is important to understand that Generation Interconnection and Resource and Load Integration cost apply to all generation resources. The primary purpose of Resource and Load Integration is to provide an overall optimal power network. Thus, RTO's must anticipate where new generation resources and loads are most likely to be located, and design the system to best integrate those added resources and loads into the regional power market. Generation Interconnection costs will depend on the robustness of the transmission system in the vicinity of where the resources are located, which depends on how well the RTO is able to forecast the future location of these resources. While these costs can vary by various configurations of resource and load locations, there is no reason to believe Generation Interconnection costs will vary because new resources are located within a transmission zone (close to the load) compared to being located outside a transmission zone (distant from the load). While it may seem that Resource and Load Integration costs would be less for generation resources located close to load, keep in mind that RTOs run energy markets that optimize the use of generation resource across the entire footprint. In order to optimize the use of generation resources (even if located within load zones), the RTO must add transmission to reduce the congestion that exists between load zones. Thus, any cost advantage of locating resources close to loads is reduced by the addition of transmission to reduce market congestion.

This leaves Transmission Service Requests for firm transmission service. Whether a new resource is located within a utility's zone or outside that zone, if the utility wants to designate that resource for network transmission service, it must submit a request to the RTO and the RTO determines whether or not upgrades are needed.

Q. WOULDN'T A TRANSMISSION SERVICE REQUEST NEED TO BE SUBMITTED FOR ALL RESOURCES REQUESTING FIRM TRANSMISSION SERVICE?

A. Yes, a transmission service request would need to be submitted for Kansas Wind + DC Transmission as well as for Midwest ISO wind. However, there is likely to be a higher cost for firm transmission service from a resource located outside the utility's transmission zone than for a resource located within the utility's transmission zone.

This difference is recognized in the Southwest Power Pool where a safe harbor amount of $180,000/MW of generation capacity is used to capture the typical cost of designating a new resource for firm network transmission service located within the utility's transmission zone. In the SPP, the utility will only be directly assigned costs that exceed this safe harbor limit. The rationale behind the safe harbor limit is that transmission service for designated network resources located outside the utility's transmission zone are likely to be more costly, and the utility should be directly assigned these additional costs rather than allowing those costs to be rolled into transmission rates. These are the added costs that should be considered for wind located outside of Ameren Missouri's transmission zone.

Q. WHAT IS THE MINIMUM LEVEL OF ADDED AC TRANSMISSION COST TO MAKE THE DC TRANSMISSION NEEDED?

A. First notice that the Kansas Wind + DC Transmission cannot meet the Missouri renewable energy requirements unless it has production tax credits. Assuming there are production tax credits, the following table shows what the added transmission costs would have to be to make the Kansas Wind project competitive with AC wind projects.

Minimum Added Transmission Costs

Capacity Factors	PTC	Total	Total	% of DC $/MWh
30%	$16.51	$85.59	NC	NC
MO 30%	$16.51	$82.22	NC	NC
35%	$16.51	$72.57	NC	NC
40%	$16.51	$62.81	$8.33	37.85%
45%	$16.51	$55.21	$15.92	72.38%
50%	$16.51	$49.13	$22.00	100.00%
Kansas DC	$16.51	$71.13	$22.00	

Notice that with production tax credits (PTC) of $16.51/MWh, the Kansas Wind + DC Transmission's cost drops to $71.13/MWh. Also, notice that, without any added transmission costs, wind having capacity factors above 35% are lower cost than wind from the Kansas Wind + DC Transmission. Taking the difference in these costs gives the maximum added transmission costs that the various alternatives can have and still be competitive with the Kansas Wind + DC Transmission. These calculations were made without losses, implicitly assuming the losses on all wind projects would be comparable. AC wind at 40% capacity factor would be less expense than Kansas Wind + DC Transmission if the added AC transmission costs are no more than 38% of the DC transmission costs. At a 45% capacity factor this ceiling increases to 72%, at 50% capacity factor the ceiling is 100% of the transmission cost for the Clean Line DC transmission project.

Q. ARE SUCH HIGH ADDED AC TRANSMISSION COSTS LIKELY?

A. The cost of the AC to DC convertors at the source and the DC to AC convertors at the sink make up approximately 25% of the total cost of the Grain Belt DC transmission line. AC transmission does not require convertors, thus it is not likely that added AC transmission would cost as much as DC Transmission.

3. ADDED AC TRANSMISSION COSTS FOR MIDWEST ISO WIND

Q. CAN YOU CALCULATE A POSSIBLE ADDED COSTS FOR WIND LOCATED OUTSIDE OF AMEREN MISSOURI'S TRANSMISSION ZONE?

A. Each case for transmission service is different and depends on the circumstances at a specific location. However, using the SPP $180/kW as a safe harbor for firm transmission service from a designated resource located within the utility's transmission zone, if the cost for firm transmission service outside the zone was two and one half this level, the total cost would be $450/kW, which is approximately 74% of the cost of the Clean Line DC transmission (i.e., the cost of the Clean Line DC transmission project minus the cost of the DC-AC and AC-DC convertors). Comparing this to the $180/kW for firm transmission within the utility's transmission zone, the added cost would be $270/kW. I would consider $270/kW an upper bound on added costs and $180/kW a lower bound. Since $270/kW is an investment cost, it needs to be levelized to make a comparison. Those levelized costs, including 5% losses, are shown on the following table where transmission costs are added to levelized wind costs without and with the production tax credit.

Levelized Cost with Incremental Transmission at $270/kW

Capacity Factors	Inc Trans Costs	LCOE with Δ Transmission Without PTC	LCOE with Δ Transmission With PTC
30%	$13.57	$121.05	$103.67
35%	$11.63	$105.41	$88.03
40%	$10.18	$93.67	$76.29
45%	$9.05	$84.55	$67.17
50%	$8.14	$77.25	$59.86
DC	$23.16	$92.26	$74.88

Without the production tax credit, the addition of incremental transmission costs and 5% losses move the capacity factor needed for wind energy to be no more than $5/MWh above

Combined Cycle generation at $91/MWh from 35% to just over 40%. With the production tax credit, AC delivered wind having just above a 40% capacity factor is more cost effective than Kansas Wind + DC Transmission.

Q. WHAT DOES THIS COMPARISON OF MIDWEST ISO WIND TO KANSAS WIND + DC TRANSMISSION SHOW CONCERNING THE NEED OF THE DC TRANSMISSION FOR MEETING MISSOURI RENEWABLE ENERGY REQUIREMENTS?

A. While the $270/kW is an estimate, it shows the potential for non-Missouri wind located in the Midwest ISO region to meet the requirements of Missouri statutes on renewable energy requirements even without production tax credits. On the other hand, Kansas Wind + DC Transmission cannot meet the requirement of Missouri statutes absent the production tax credit. Based on a reasonable estimate for added transmission costs for wind located in the Midwest ISO footprint, but not in Missouri, wind having capacity factors in the range of above 40% are more cost-effective alternatives than Kansas Wind + DC Transmission.

Q. WHAT DOES THIS COMPARISON OF MIDWEST ISO WIND TO KANSAS WIND + DC TRANSMISSION SHOW CONCERNING THE ECONOMIC VIABILITY OF KANSAS WIND + DC TRANSMISSION?

A. There is little question that with environmental restrictions on air pollutants becoming stronger that energy from renewable resources will become very important for replacing fossil fuel generation. However, all utilities, investor-owned, municipals and co-operatives will want to acquire energy from wind resources at the lowest possible cost. The comparison of Kansas Wind + DC Transmission to Midwest ISO wind clearly indicates that Midwest ISO wind is the lower cost alternative.

II. REBUTTAL OF THE DIRECT TESTIMONY OF GARY MOLAND

A. OVERVIEW

Q. WHAT PORTIONS OF GARY MOLAND'S DIRECT TESTIMONY ARE YOU ADDRESSING?

A, Mr. Moland's direct testimony is very short, and I will be addressing his entire testimony.

Q. WHAT IS THE STATED PURPOSE OF MR. MOLAND'S DIRECT TESTIMONY?

A. Mr. Moland presents the assumptions and results of a model used to measure the economic and environmental impacts of the DC Transmission project.

Q. BRIEFLY, WHAT ARE MR. MOLAND'S FINDINGS?

A. Mr. Moland finds that by adding the wind generation from the DC Transmission projects, wholesale electricity prices for energy drop in Missouri, lower overall production costs and reduce emissions.

Q. DO YOU HAVE ANY DISAGREEMENT WITH THESE FINDINGS?

A. No, I do not. It is a well-accepted fact in the electricity industry that energy from wind will lower prices, production cost and emissions. Mr. Moland's study simply confirms that fact. However, had Mr. Moland performed a similar study with wind energy from the Midwest ISO region, he would have made similar findings.

Q. DID MR. MOLAND PROVIDE ANY COMPARISONS TO WIND ENERGY FROM THE MIDWEST ISO?

A. No, he did not. Instead at page 5 of his direct testimony Mr. Moland argues *"This benefit study is unique in that the economic feasibility of the Project and the new wind generation resources that will utilize it are directly intertwined, such that one cannot be reasonably modeled without the other. The Project serves no purpose without the new wind resources* *and the new wind resources would not be developed without the transmission access afforded by the Grain Belt Express Project."*

Q. DO YOU DISAGREE WITH MR. MOLAND'S ARGUMENT?

A. If Mr. Moland had instead said that *"Kansas wind energy cannot be* ***physically*** *delivered to the destinations in Missouri and Indiana except by a DC Transmission project,"* I would agree with him. DC transmission that is directly connected to generation does provide for the delivery of the energy physically produced at the generation source minus transmission losses.

However, I found his statement to be somewhat misleading and confusing. Moreover, Mr. Moland provides no evidence to support his claim that the new wind resources in Kansas would not be developed absent the DC Transmission project. Even if his statement were true, it only bears on this case to the extent that Kansas Wind + DC Transmission is the most overall cost-effective way of meeting Missouri's renewable energy needs.

On the other hand, if Mr. Moland's statement is meant to imply that other new wind resources in the Midwest ISO cannot be developed to meet the need for renewable energy in Missouri, then I totally disagree.

B. STUDY FUTURES AND ASSUMPTIONS

Q. DO YOU AGREE WITH THE STUDY FUTURES USED IN MR. MOLAND'S STUDY?

A, I did not totally agree with some of his futures. I did agree with his treatment of wind to meet state mandates in three of his futures (Business as Usual, Slow Growth and Robust Economy). Mr. Moland then includes a Green Economy future with Carbon cap and trade and federal renewable energy standards. I would have preferred the three futures described previously in my testimony related to government policy: 1) Business As Usual; 2) Likely Changes; and 3) Aggressive Changes. If a slow or robust economy is used, I would have added the slow economy to the government policy in business as usual (which is what Mr. Moland did), but for the robust economy future I would have used the government policy in the likely changes future. Finally, the addition of the PATH transmission project to the east coast in the robust economy future appears to make sense as it was cancelled because of low load growth. However, as an analyst I would want to confirm the cost-effectiveness of this project before including it in a future.

Q. DID YOU AGREE WITH MR. MORLAND'S MODEL ASSUMPTIONS?

A. Mr. Moland uses Ventex's modeling data for generation, load and fuel cost forecasts, and updated information on the existing and proposed upgrades to the transmission system. Ventex data is recognized in the industry as a reasonable data source, and I have no reason to disagree with this data or the data used for the transmission system.

C. METRICS FOR MEASURING ECONOMIC BENEFIT

Q. WHAT METRICS DID MR. MOLAND USE FOR HIS ECONOMIC ANALYSIS?

A. Mr. Moland used: 1) the wholesale electricity cost to Missouri loads; 2) the production costs of generators in eastern US; and 3) the wholesale electricity prices in Missouri.

Q. ARE THESE THE USUAL METRICS USED FOR EVALUATING ECONOMIC BENEFIT?

A. No, they are not. Both the Southwest Power Pool and the Midwest ISO use the Adjusted Production Cost (APC) metric to measure economic benefit between a base and change case. APC can be measured for a grouping as small as a utility's transmission zone (e.g., Ameren Missouri) or several utilities within a single transmission zone. APC can also be measured for a grouping as large as an RTO (e.g., Midwest ISO) or groupings of RTOs. While it can be applied to a state, this is usually done by applying to utilities and then allocating the results to multiple states served by utilities.

APC is made up of three components: 1) Production Costs; 2) Purchased Power Costs (Purchases) from energy purchased by the utility from the RTO energy market; and 3) Revenues from Sales (Sales) of energy by the utility to the RTO energy market; where APC = Production Costs + Purchases – Sales. These three components are calculated each hour for each utility. Energy purchased or sold is calculated as the difference between the utility's load and its generation. Purchases are monetized using the prices paid by the load, and sales are monetized using the prices paid to generators.

Q. WHY IS THE APC METRIC USED BY RTOS?

A. Using APC as a metric allows RTOs to measure the economic benefits specific to each zone within the RTO as well as the overall economic benefits to their footprint.

Q. HOW WOULD USING THE APC METRIC HAVE IMPROVED MR. MOLAND'S MEASURES OF BENEFITS?

A. Had Mr. Moland used the APC metric he would have been able to measure the specific benefits to Ameren Missouri as well as the other utilities in Missouri.

D. <u>METRICS USED FOR ENVIRONMENTAL BENEFITS</u>

Q. WHAT METRICS DID MR. MOLAND USE FOR ENVIRONMENTAL BENEFITS?

A. Mr. Moland used: 1) SO_2; 2) NO_x; 3) Hg; 4) CO_2; and 5) H_2O usage.

Q. WHAT WERE MR. MOLAND'S FINDINGS?

A. Mr. Moland found that all emission and water usage were reduced with the introduction of added wind generation.

Q. DO YOU AGREE WITH MR. MOLAND'S FINDINGS?

A. As stated previously, it is an accepted fact in the electric industry that emissions and water usage will decrease with added wind generation. This is because wind generation has the lowest energy costs, is therefore loaded before fossil generation and reduces emissions and water usage associated with fossil generation. What might be of greater interest is whether wind generation from within the Midwest ISO has the same impact?

Q. CAN THESE REDUCTIONS IN EMISSION AND WATER USAGE BE MEASURED FOR SPECIFIC UTILITIES?

A. Yes. Both emissions and water usage is generation plant specific, and by measuring these metrics for each utility's generators and reductions can be determined on a utility-by-utility basis. What would have been of interest is whether the DC Transmission project results in greater reductions in emissions and water usage for Missouri utilities when compared to wind generation from the Midwest ISO located outside of Missouri.

III. RECOMENDATIONS

Q. WHAT IS YOUR RECOMMENDATION TO THE MISSOURI COMMISSION?

A. As an economist, I must evaluate all of the potential benefits of Kansas Wind + DC transmission against the potential costs. A possible indirect benefit of Kansas Wind + DC transmission is that it provides an alternative source of renewable energy. However, my rebuttal testimony demonstrates that under reasonable assumptions and forecasts Kansas Wind + DC transmission would not be competitive with other alternatives available to Ameren Missouri to meet its need for energy and capacity, including meeting its renewable energy requirements from Missouri legislation. Thus, at best, the availability of what is likely to be a less than competitive alternative is a marginal benefit.

Comparing the marginal benefit of the Kansas Wind + DC transmission to the cost for Missouri land owners who would have to give up portions of their properties to provide the land needed to bring the DC project to fruition, my recommendation to the Commission is to deny the applicant's request for a certificate of convenience and necessity ("CCN") to operate in the state of Missouri.

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 the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing it to Construct, Own, Operate, Control, Manage, and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an interconnection on the Maywood-Montgomery 345 kV Transmission Line	)	Case No. EA-2014-0207

AFFIDAVIT OF MICHAEL S. PROCTOR

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Michael S. Proctor, being first duly sworn on his oath, states:

1. My name is Michael S. Proctor. I am currently an independent consultant. My home address is 2172 Butterfield Drive, Maryland Heights, MO 63043.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Show Me Concerned Landowners, consisting of 42 pages, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

2. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and accurate to the best of my knowledge, information and belief.

Michael S Proctor
Michael S. Proctor

Subscribed and sworn to before me this 9th day of September, 2014.

Pamela S. Backers
Notary Public

Pamela S. Backers
Notary Public - Notary Seal
STATE OF MISSOURI
Cole County
Commission # 14398160
My Commission Expires 7/12/2018

My commission expires: 7/12/18

CURRICULUM VITA

Michael S. Proctor

Education:

1965, B.A. in Economics, University of Missouri, Columbia

1967, MA in Economics, University of Missouri, Columbia

1970, PhD in Economics, Texas A&M University

Work Experience:

1970 – 1973: Assistant Professor of Economics at Purdue University

1973-1977: Assistant Professor of Economics at University of Missouri, Columbia

1977-2009: Missouri Public Service Commission (Retired August 31, 2009)

2009-Current: Consultant on Issues Related to Electricity Markets and Transmission Expansion

Areas of Expertise and Experience:

Economics: University Professor (1970 – 1977)

Micro-economics: Specialized in investment theory for the firm and taught senior and graduate level micro-economics and macro-economics at Purdue and Missouri Universities.

Optimization: Taught optimization methods in MBA programs at Purdue and Missouri Universities.

Econometrics & Statistics: Taught statistics in undergraduate business courses at Purdue University.

Regulatory: Manager of Economic Analysis Department (1978-1992)

Class cost of service studies: Classify natural gas and electric utility costs with respect to usage factors that relate to cost causers and beneficiaries, and use of load research data to develop allocation factors corresponding to class usage.

- Managed a department at the Missouri Public Service Commission that was responsible for performing class cost of service studies.

- Advanced moving from the strict cost causation method of peak demand allocations to the beneficiary pays method of capacity utilization and the associated average and peak allocation factor.

Rate design: For natural gas and electric utilities, develop various rate structures that collect targeted costs, allocate costs to individual customers within a class and provide customers with price incentives for energy use.

- Advanced the use of billing determinants and class load curves for the purpose of implementing new rate designs, including time-of-use rates.

Resource Planning: Review economic analysis of both supply-side and demand-side alternatives to meet utilities resource needs.

- Led the development of the Missouri Commission's first integrated resource planning rule, and application of this rule for the Missouri, Investor-Owned Utilities.

Load Analysis: Use of econometric and end-use modeling techniques for both short-term and long-term forecasts of utility customers demand for energy.

- Developed statistical techniques for analysis of the relationship of demand for electricity to weather, and implemented these methods in rate cases for estimation of weather normalized usage.

Regulatory: Chief Economist for MoPSC (1992-2009)

Analysis of electricity markets:

- Participated in the design of regional markets for the Midwest ISO and Southwest Power Pool.
- Represented the Missouri Commission on various working groups of the Organization of Midwest ISO States, and chaired the working group for the allocation of Financial Transmission Rights.
- Chaired the Cost Allocation Working Group of the Regional State Committee at the Southwest Power Pool.
- Regularly participated in electric rate cases before the Missouri Commission as an expert witness on utility purchases and sales of electricity, as well as in electric merger cases as an expert in evaluating potential increases in market power resulting from a merger.

Consultant: Regional Electricity Markets, Transmission Planning and Cost Allocation (1999-Present)

Transmission planning and allocation of the costs of transmission upgrades:

- Consult with the Southwest Power Pool's (SPP's) Regional State Committee (RSC) in the economics related to cost allocations for what the SPP calls Integrated Transmission Planning – a process that develops cost-effective transmission upgrades on a forward-looking basis.

Transmission planning and benefit metrics related to transmission upgrades:

- Participate in the SPP's Economics Study Group with a focus on the specification of and metrics for benefits from transmission upgrades designed to meet the reliability, public policy and economic needs of the SPP region.

Miscellaneous consulting activities: Several contracts on various issues related to wholesale electricity markets:

- Missouri Public Service Commission: Provided educational information on regional electricity markets.
- Organization of MISO States: Provided technical information on Extended Locational Marginal Pricing.
- Show-Me Power Cooperative: Provided reports and testimony on wholesale rate design.
- City of Owensville: Provided information on stranded cost related to wholesale electricity contract.

Executive Summary

I. Rebuttal to Mr. David Berry

The following table compares Dr. Proctor's estimated levelized cost to Mr. Berry's estimates absent a production tax credit for wind generation.

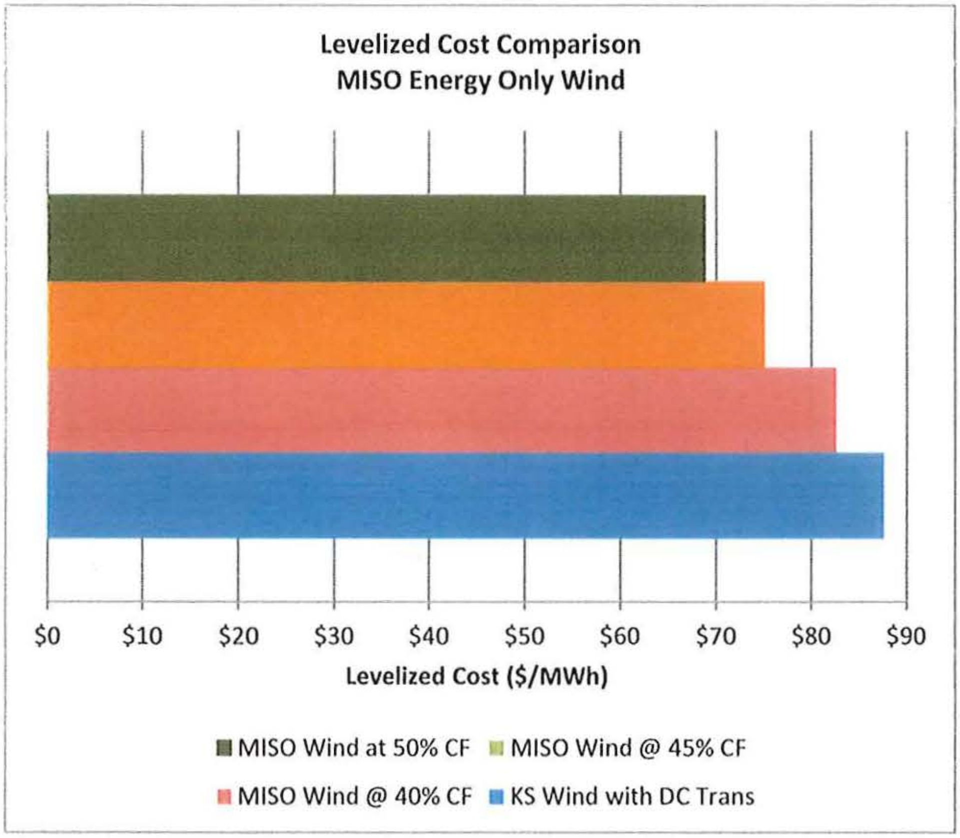
COMPARATIVE RESULTS FOR LEVELIZED COSTS

Alternatives	Levelized Costs $/MWh-yr		
	Proctor	Berry	Difference
Kansas Wind	$92.26	$41.86	$50.40
Missouri Wind	$98.73	$56.94	$41.79
Combined Cycle	$85.97	$111.18	($25.21)

While Mr. Berry's analysis shows Kansas Wind to be competitive with both Missouri Wind and natural gas fired Combined Cycle generation; Dr. Proctor's analysis shows that Kansas Wind is not competitive with Combined Cycle generation absent a production tax credit for wind. Thus, the Clean Line DC Transmission (DC Transmission) project does not pass the economic viability requirement of the Missouri Public Service Commission (Missouri Commission).

In terms of need, Dr. Proctor argues that to meet Missouri's renewable energy requirement, Mr. Berry should have compared the Kansas Wind + DC Transmission with wind alternatives not located in Missouri using AC transmission service provided through the Midwest ISO. This comparison can be performed either treating Midwest ISO wind as an energy-only resource or as an energy and capacity resource with firm transmission service. In either case, Midwest ISO wind is competitive with Kansas Wind + DC Transmission.

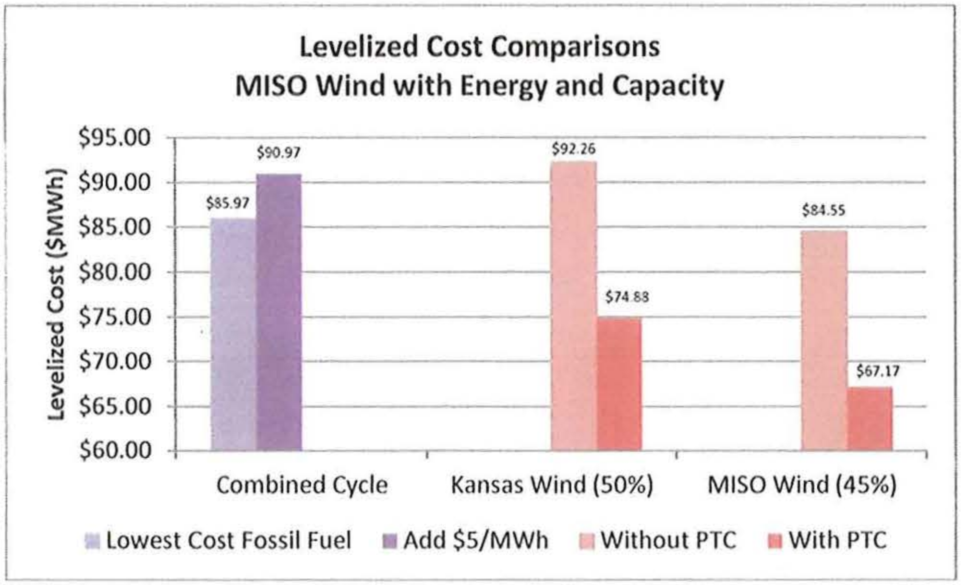
Energy-Only Resource: The following chart compares Midwest ISO wind with the addition of combustion turbine capacity to Kansas Wind + DC Transmission, where in both cases the capacity is added to make both alternatives have the same Unforced Capacity (UCAP) as a combined cycle alternative, and production tax credits and losses are not included.



Analysis of the Midwest ISO's 2013 markets for Financial Transmission Rights (FTRs) shows that over 97% of the prices paid for FTRs are less than the cost savings from Midwest ISO wind compared to Kansas Wind + DC Transmission. This means that cost savings to Ameren Missouri from Midwest ISO wind is almost certain to cover any congestion costs.

Energy and Capacity Resource: The following chart compares wind alternatives (with and without a federal production tax credit) to the Missouri statute requiring wind to be no more than $5/MWh above the cost of non-renewable resource alternatives. This chart shows that wind located in the Midwest ISO footprint at a lower capacity factor (45% in chart) than Kansas Wind

(50% in chart) can meet the Missouri renewable energy requirements without the production tax credit and are more cost-effective than Kansas Wind + DC Transmission.



This same result holds for Midwest ISO wind with capacity factors as low as 41%. Therefore, neither the uncertain future production tax credit nor the DC Transmission project is needed to meet the Missouri renewable energy requirements.

II. Rebuttal to Mr. Gary Moland

Dr. Proctor shows why Mr. Moland's testimony is not relevant to the economic viability for approving the DC Transmission project. It is well known that wind generation lowers the wholesale prices for electricity and decreases environmental emissions, but because of the high investment costs associated with the DC transmission line, that fact does not make wind generation a viable economic alternative.

Had Mr. Moland performed a similar study with wind energy from the Midwest ISO region, he would have made similar findings. Thus, Mr. Moland's testimony does not address the need for the Kansas Wind + DC Transmission.