Q2 2012 Earnings Call

Company Participants

- Doug Fischer, Director of IR
- Marty Lyons, SVP and CFO
- Maureen Borkowski, President and CEO Ameren Transmission
- Tom Voss, President, CEO and Chairman
- Warner Baxter, President and CEO Ameren Missouri

Other Participants

- Andy Bishop, Analyst, Morningstar
- Brian Taddeo, Analyst, Gleacher and Company
- David Paz, Analyst, Bank of America
- Julien Dumoulin-Smith, Analyst, UBS
- Kevin Fallon, Analyst, SIR Capital
- Michael Lapides, Analyst, Goldman Sachs
- Paul Patterson, Analyst, Glenrock Associates
- Stephen Byrd, Analyst, Morgan Stanley

Presentation

Operator

Greetings, and welcome to the Ameren Corporation's Second Quarter 2012 earnings call. At this time, all participants are in a listen-only mode. A brief question-and-answer session will follow the formal presentation. (Operator Instructions) As a reminder, this conference is being recorded. It is now my pleasure to introduce your host, Doug Fischer, Director of Investor Relations for Ameren Corporation. Thank you, Mr. Fischer, you may now begin.

Doug Fischer {BIO 16481971 <GO>}

Thank you, and good morning. I'm Doug Fischer, Director of Investor Relations for Ameren Corporation. On the call with me today are Tom Voss, our Chairman, President and Chief Executive Officer; Marty Lyons, our Senior Vice President and Chief Financial Officer; and other members of the Ameren management team. Before we begin, let me cover a few administrative details. This call is being broadcast live on the internet, and the webcast will be available for one year on our website at www.Ameren.com. Further, this call contains time-sensitive data that is accurate only as of the date of today's live broadcast. Redistribution of this broadcast is prohibited. To assist with our call this morning, we have posted a presentation on our website that will be referenced during this call. To access this presentation, please look in the Investor section of our website under Webcast and Presentations, and follow the appropriate link.

Turning to page two of the presentation, I need to inform you that comments made during this conference call may contain statements that are commonly referred to as forward-looking statements. Such statements include those about future expectations, beliefs, plans, strategies, objectives, events, conditions and financial performance. We caution you that various factors could cause actual results to differ materially from those anticipated and described in the forward-looking statement. For additional information concerning these factors, please read the forward-looking statement section in the news release we issued today, and the forward-looking statements and risk factor sections in our filings with the SEC. Tom will begin this call with an overview of Second Quarter 2012 earnings and 2012 guidance, followed by a discussion of recent regulatory and business developments. Marty will follow with more detailed discussions of Second Quarter 2012 financial results, and regulatory and other financial matters. We will then open the call for questions. Here is Tom, who will start on page three of the presentation.

Tom Voss {BIO 1892060 <GO>}

Thanks, Doug. Good morning, and thank you for joining us. I am pleased to report that today we released Second Quarter 2012 core earnings of $0.73 per share, compared to $0.59 per share of core earnings in the Second Quarter of 2011. This improvement reflected increased earnings from our regulated utility operations, partially offset by decreased earnings from our merchant generation operations. Key drivers of the higher regulated utility earnings were -- a favorable federal energy regulatory commission order related to a disputed Ameren Missouri power purchase agreement that expired in 2009; the absence in 2012 of a 2011 Ameren Missouri charge to earnings related to the field adjustment clause; and 2011 Missouri Electric and 2012 Illinois gas rate adjustments. Other factors having a favorable effect on Second Quarter 2012 regulated utility earnings compared to Second Quarter 2011 regulated utility earnings included reduced storm-related costs and increased electric sales to native load customers resulting from warmer temperatures. Merchant generation earnings were negatively impacted by lower prices for electricity. Marty will provide more details on our Second Quarter earnings in a few minutes. Turning to page 4, based on Second Quarter results, today we are raising our 2012 core earnings guidance range to $2.25 to $2.55 per share, from a prior range of $2.20 to $2.50 per share. Our core earnings guidance range for our merchant generation business segment remains $0.05 to $0.15 per share. The favorable earnings impact of warmer than normal Second Quarter temperatures, and the previously mentioned FERC order on the disputed power purchase agreement, have led us to raise core guidance for our regulated utility businesses by $0.05 per share, at both the low and high ends of the range, to a new range of $2.20 to $2.40 per share. This guidance assumes normal temperatures for the second half of the year, and so far, Third Quarter temperatures have been much warmer than normal. And I am very pleased to note that during the current extended period of very warm weather, which began with record temperatures in May, our utility systems have performed well, demonstrating the value of the significant reliability investments we have made in recent years. Extreme weather puts strains not only on our system, but also on our customers we serve and our employees. We continue to provide a range of assistance to help low-income customers cope with the impacts of warm weather. These include promoting and contributing to programs that assist low-income customers with their bills, and annual donations of residential air conditioning units to local charities for distribution. Also want to commend our employees, especially our generating center, substation mechanics, and line workers for their dedication and focus on safety. They work hard in the heat, so that our customers can stay cool. Moving to page 5, we have significant electric rate cases pending in both Missouri and Illinois, with decisions from the utility regulators in these states expected later this year. While Marty will update you on other details of these proceedings, I want to touch on some policy issues. We continue to believe that modern, constructive, regulatory frameworks, which provide timely cash flows and a reasonable opportunity to earn fair return on investments, are clearly in the best long-term interest of our customers, and the states in which we operate. These frameworks support our ability to attract capital on terms which facilitate the timely investment needed to modernize our regulated utilities companies' aging infrastructure, and meet customers' expectations for safe, reliable, and clean energy. Constructive regulatory framework and the investment they facilitate also help create good paying jobs. In our pending electric rate case in Missouri, we are seeking recovery of costs in investments we have already made to serve customers. Further, we are seeking to enhance the existing regulatory framework in the state. As a result, we have made several new proposals in this case. First, we are requesting approval of a storm cost tracking mechanism, that will provide the opportunity to recover costs to restore service after major storms in a matter that is fair to both our customers and our investors. Second, we are requesting approval of a new plant in-service accounting proposal. This proposal is designed to reduce the impact of regulatory lag on earnings and future cash flows, related to assets placed in service between rate cases. In a related regulatory matter, early this year, Ameren Missouri filed a request with the Missouri Public Service Commission for approval of new and expanded energy efficiency programs for the three-year period beginning in January 2013. This was the utility's first request under the Missouri Energy Efficiency Investment Act, or MEEIA. Last month, all of the parties to the energy efficiency proceeding filed a stipulation and agreement with the Missouri Public Service Commission, resolving all related issues. And yesterday, the PSC unanimously approved this agreement. This agreement aligns the utility's financial incentives with those of customers, consistent with the MEEIA legislation. It provides timely recovery of the expected cost of the energy efficiency programs we will implement beginning in January of 2013. And the revenue requirement for these program costs will be included in our pending electric rate case, with true-ups to actual costs in future rate cases. And also for the first time, we will receive timely recovery through rates that is designed to offset revenue losses of fixed costs, occurring as a result of implementing our energy efficiency programs. Further, the calculation for such recovery will be based on predetermined values for specific energy efficiency actions, rather than difficult and often contentious after-the-fact measurement. Here also, the associated revenue requirement will be included in the pending rate case with true-ups in future rate cases. Finally, the energy efficiency agreement will provide an opportunity for us to earn a performance incentive, to reflect the rate base growth foregone as a result of our energy efficiency programs. Any earned performance incentive will be calculated and collected after 2015, with any earnings benefit expected to be recognized in 2016. Moving now to Illinois, constructive formula rate making is in place for our state regulated electric delivery service, and, as Marty will discuss, our initial and first annual update formula rate cases are pending before the ICC. Given the constructive formula rate making framework, we are moving forward with plans to invest meaningful incremental capital in this business. Over the next 10 years, our Illinois electric delivery business is required to invest $625 million over and above levels we have been spending in recent years, and create 450 jobs during the peak program year. The improved infrastructure resulting from these investments will enhance reliability, and provide customers with the energy usage options made possible by smart meters. Turning now to page 6, I would like to update you on progress in growing our investments in FERC regulated transmission projects at the Ameren Illinois and Ameren Transmission Companies. Such projects benefit from constructive FERC formula rate making. Ameren Illinois is moving forward with its plans to invest approximately $900 million across some 300 projects over the five years ending in 2016, which are focused on reliability and local load growth needs. As shown in the pie chart, 75% of the planned $900 million investment is in projects that do not require regulatory approval, because they are improving or rebuilding existing lines. The remaining investments, which are for five greenfield projects, do require regulatory approval, and as noted on the slide, two of these projects have already been granted such certificates. On page seven we provide an update on Ameren Transmission Company, or ATX, projects. ATX is moving forward with its plans to invest approximately $750 million in greenfield regional projects within Illinois and Missouri over the five years ending in 2016. The bulk of ATX's investment over this period will be in the $800 million-plus Illinois rivers project, a MISO approved regional multi-value project to build a transmission line across the state of Illinois. We are currently holding public meetings on route design for this project. Later this year, we plan to file for a certificate of public convenience and necessity, and an ICC decision will be issued by July of 2013. Once we receive the certificate, we will begin to acquire right-of-way. Preliminary construction may start as early as 2013, with a full range of construction activities in 2014. Meanwhile, we recently filed with the FERC requesting the same constructive rate treatment that we have already received for the Illinois Rivers Project for ATX's two other MISO approved regional multi-value projects. Turning now to page 8, I would like to comment on our merchant generation business. We continue to act to adjust this business to weak power prices and an uncertain timeline for their recovery. As we discussed on our First Quarter call, our merchant generation business filed a request for a variance from the Illinois Multi-Pollutant Standard, or MPS, with the Illinois Pollution Control Board in May. In our petition, we outlined our need for additional time to comply with sulfur dioxide emission levels currently set to become effective January 1, 2015. In exchange for delaying compliance with these levels through 2020, we have proposed a compliance plan that restricts our sulfur dioxide emissions through 2014, to levels lower than those required by the existing MPS. Thereby offsetting the environmental impact of granting the variant relief. Further, our variance compliance plan will also comply with federal emission rules that are currently stayed, but are under review by the federal courts. There have been significant public interest in our variance request with various citizens groups, and the Illinois Attorney General's office opposing, and labor and local community interests supporting the variance request. Only the Illinois Environmental Protection Agency and our merchant business are parties at the proceedings. The Illinois EPA has filed a mutual recommendation, but has noted that our compliance plan results in a net environmental benefit. If we are not granted the variance, or power prices do not materially increase, there is a significant risk that we will have to mothball two of our three unscrubbed merchant generation coal fired energy centers beginning in 2015. Pollution Control Board held a hearing on our variance request just yesterday, and it must decide the matter by September 20 of this year. I want to conclude my prepared remarks by noting that the focus of our dedicated employees on maintaining solid operating performance and improving customer service, our active management of our merchant generation business, and our disciplined cost management and capital allocation, all reinforce my optimism as to the future prospects of Ameren. Now, I will turn the call over to Marty.

Marty Lyons {BIO 4938648 <GO>}

Thanks, Tom. Turning to page nine of the presentation -- today we reported a Second Quarter 2012 GAAP earnings of $0.87 per share, compared to Second Quarter 2011 GAAP earnings of $0.57 per share. Excluding certain items in each year, Ameren recorded Second Quarter 2012 core earnings of $0.73 per share, compared with Second Quarter 2011 core earnings of $0.59 per share. Second-quarter 2012 core earnings excluded two items that are included in GAAP earnings. The largest of these non-core items was the increase in income tax benefit as a result of the First Quarter 2012 non-cash asset impairment charge at our merchant generation business, and the GAAP requirement to recognize quarterly income tax expense using the annual estimated effective income tax rate. This item increased net income by $0.18 per share in the Second Quarter of 2012, partially reversing the $0.36 per share First Quarter 2012 charge. We expect the remaining $0.18 per share of this year-to-date expense to be fully reversed by the end of the year. The second non-core item is a $0.04 per share loss from the net effect of unrealized mark-to-market activity. On page 10, we highlight key factors that drove the $0.14 per share improvement in Second Quarter 2012 core earnings, compared to Second Quarter 2011 core earnings. These key factors included electric and gas rate adjustments, net of certain related expenses, which increased earnings by $0.09 per share. Electric rates changed in Missouri in late July of last year, and gas delivery rates changed in Illinois in January of this year. A second factor favorably impacting the comparison is the previously discussed favorable FERC order, regarding the disputed power purchase agreement. This added $0.07 per share to Second Quarter 2012 earnings. The earnings comparison also benefited from the absence of the previously discussed Second Quarter 2011 fact [ph] related charge of $0.05 per share. In addition, lower storm related costs benefited Second Quarter 2012 earnings by $0.04 per share. You will recall that we experienced severe storms in the Second Quarter of last year, resulting in high storm restoration expenses. Further, warmer than normal temperatures boosted earnings by an estimated $0.03 per share, compared to the Second Quarter of 2011, a period that was also warmer than normal. We estimate that the warm Second Quarter 2012 temperatures increased earnings by $0.07 per share, compared to normal, offsetting a significant part of the estimated $0.10 per share negative impact compared to normal experienced in the First Quarter of this year due to mild winter temperatures. Second-quarter 2012 cooling degree days were 30% greater than normal and 15% greater than those experienced in the Second Quarter of 2011. Reflecting this, Second Quarter 2012 kilowatt hour sales of electricity to weather-sensitive residential and commercial utility customers rose 2%, compared to the Second Quarter of 2011. Excluding the impacts of weather, we estimate that Second Quarter and first-half 2012 kilowatt hour sales to residential and commercial customers were flat with those of the Second Quarter and first half of 2011. A decline in margins at the merchant generation business reduced earnings by $0.10 per share, primarily a result of lower power prices. Turning now to page 11, we have raised our 2012 cash flow projection. We now expect 2012 negative free cash flow of approximately $190 million, an improvement of $40 million from our prior projection. The improved cash flow outlook reflects higher expected cash flows from operations, as a result of the previously discussed favorable FERC order and our increased earnings expectations. As shown on this page, we calculate free cash flow by starting with our projected cash flows from operating activities, and subtracting from it expected capital expenditures, other cash flows from investing activities, dividends, and net advances for construction. While we anticipate that free cash flow will be negative for Ameren as a whole, we expect our merchant generation business will cover its own cash needs. Moving to page 12 of our presentation, I would like to update you on selected recent regulatory developments impacting our various business segments. Beginning with Ameren Missouri, as I mentioned earlier, the FERC has issued a favorable order in a longstanding case involving a disputed power purchase agreement that expired in 2009. The FERC's May 2012 order firmed its 2010 ruling that Entergy Arkansas should not have included additional charges to Ameren Missouri under the power purchase agreement, and required Entergy to refund the improper charges with interest. Ameren Missouri received cash reimbursement from Entergy in June. The portion of the reimbursement related to power purchase before implementation of the Missouri fuel adjustment clause in February of 2009, an amount that was never included in customers' rates, was reflected in Second Quarter 2012 earnings. Meanwhile, Entergy has appealed the FERC order to the US court of appeals. In a second recent regulatory development involving our Missouri utility, the state circuit court has reversed the Missouri Public Service Commission's 2011 order requiring that $18 million related to sales ending in September of 2009 under certain wholesale contracts, be flowed to customers through the FAC. As a result of that 2011 PSC order, we took a charge to earnings in the Second Quarter of 2011, and have completed flowing these funds to customers through the FAC. In response to the favorable circuit court ruling, the PSC recently appealed the matter to the Missouri court of appeals, and this decision is not expected until 2013. As a result, we have not reversed the charge we took in 2011. The PSC has reviewed the final $26 million relating to these same wholesale contracts for the period ending in May 2011, and is expected to issue a decision later this year as to whether this additional amount should be flowed to customers through the FAC. A negative PSC decision on this matter would result in a charge to earnings. At the top of page 13, we list a recent positive development impacting our Ameren Illinois electric delivery business. Last month, the ICC decided to consider Ameren Illinois's modified smart grid advanced metering infrastructure, or AMI, deployment plan. Installing smart grid equipment in advanced two-way electric meters is critical in meeting the infrastructure enhancements required under the Illinois Energy Infrastructure Modernization Act that authorized formula rates, and such expenditures comprise about 50% of the increase in capital spending required by the Act. In March 2012, Ameren Illinois submitted its original smart grid advanced metering infrastructure deployment plan to the ICC, and the ICC subsequently denied that plan in May of 2012. The ICC ruled that Ameren Illinois's original plan did not provide enough support to prove that it was cost beneficial for electric customers. Â¶ Ameren Illinois asked for a rehearing, and filed a modified deployment plan designed to address the ICC's concerns about cost justification. Our rehearing filing demonstrated a positive net present value for a plan which provides for the installation of advanced electric meters for 62% of electric customers within 10 years. The ICC is scheduled to rule on our modified plan in November of 2012, and we are optimistic about a positive outcome. Assuming ICC approval, we would begin our construction of infrastructure in the Third Quarter of 2013, with the first meters to be installed in the Second Quarter of 2014. And finally, I would like to update you on a recent FERC regulatory development. In June, the FERC issued an order in the electric capacity construct filing of the Midwest Independent Transmission System Operator, or MISO. The FERC approved MISO's request to change the capacity construct to an annual from a monthly capacity construct, beginning with the 2013 to 2014 planning year. We are disappointed with the FERC's order, and continue to maintain that a multi-year, forward capacity construct is necessary to provide the transparent price signals needed to ensure electric reliability over the long term. However, in an encouraging aspect of the order, the FERC directed staff to solicit comments in a separate proceeding on the issue of capacity portability between MISO and PJM. This includes an examination of administrative rules that may act as barriers to capacity transfers across the MISO/PJM seam, and potential solutions. We continue to support the removal of unnecessary barriers to capacity portability across the seam as a means of improving market efficiency. Moving to page 14, I would like to update you on the first of our two pending Illinois electric delivery formula rate case. While the outcome of the initial case, filed in January of this year, will establish the level of rates charged to customers from October through the end of this year, it is important to emphasize that full-year 2012 electric delivery earnings will reflect a true-up for 2012 rate base, actual cost of service, and the formula based return on equity, as well as historical ICC rate making adjustment. To assist you in thinking about the expected 2012 earnings power of our Illinois electric delivery business, we have provided estimates of several of the key inputs into the rate formula. Moving to a discussion of the pending initial formula rate case, this filing, as we updated it in July, called for a $20 million annual rate decrease compared to current rates. In July, the ICC staff filed their most recent testimony in this case. The ICC staff recommended that rates be decreased by $29 million annually, more than the Ameren Illinois's updated proposal. The ICC staff's recommended revenue requirement reflects $20 million of lower rate base, with $14 million of this $20 million the result of downward rate base adjustments for estimated accumulated deferred income taxes. We have listed several of the other staff recommended adjustments to the revenue requirement on this page. On page 15, we have summarized the positions of the other major interveners in this case. The revenue requirement recommended by these parties range from $33 million to $37 million lower than our updated request, and many of their positions on the issues are similar to those of the staff. We, and the other parties to this case, have different views on another issue related to the rate base and capitalization amounts to be used for both rate making and the eventual earnings true-up calculation. We argue that the legislation specifies that rate base and capitalization for a given year should be based on year-end values. The ICC staff and other interveners recommended that the ICC use average values for a given year. In fact, the ICC adopted average values in a recent Commonwealth Edison order. However, in late June, the ICC voted unanimously to rehear certain parts of its May Commonwealth Edison order, including the use of average as compared to year-end rate base, and the method for calculating interest on the revenue requirement reconciliation. In addition to these issues, the attorney general has recommended an additional $7 million revenue reduction, by crediting Ameren Illinois's electric delivery cost of service with the benefit of the full amount of electric late payment revenue, including the over 50% related to power supply, rather than just the portion related to delivery service. Finally, the Illinois industrial energy consumers recommended limiting the common equity ratio to 50% rather than the higher amount in our filing. We strongly believe that this proposed adjustment is unjustified. The ICC administrative law judges are expected to issue their proposed order in this case in August, with an ICC decision expected in late September, and new rates to be effective in October 2012. Turning now to page 16. In April, Ameren Illinois made its first annual electric delivery formula rate update filing. Again, while the outcome of this update case will establish the level of rates charged to customers beginning in January 2013, full-year 2013 electric delivery earnings will reflect a true-up for 2013 rate base, actual cost of service, and formula return on equity, as well as historical ICC rate making adjustment. As updated in July, this filing calls for an incremental $16 million annual rate decrease, in addition to our updated request in the initial formula rate case that I just discussed. The reduction in rates beyond those filed in the initial case primarily reflects lower rate base and return on equity. The lower rate base in this filing compared to the amount we supported in the initial case primarily reflects the incorporation of 2011 accumulated deferred income taxes, including bonus depreciation. The ICC staff and other interveners have filed their initial recommendations in the updated case. Details of their position are outlined at the bottom of page 16 and on page 17. They advocated incremental rate decreases that range from $12 million to $23 million more than our proposed $16 million rate reduction. Their arguments were along the same lines they put forward in the initial formula rate case. Further, the ICC staff argued that the equity ratio should be limited to 51%, which reduced the revenue requirement by $4 million. In addition, the Attorney General and the Citizens Utility Board argued that the revenue requirements should be reduced by $5 million and $3 million, respectively, to reflect the impact on deferred taxes of the 2011 change to the Illinois corporate income tax rate. The ICC administrative law judges are expected to issue their proposed order in this case by early November, with an ICC decision expected in December, and new rates to be effective in January 2013. Moving now to page 18, in an update on our pending Missouri electric rate case, we have requested a $376 million increase, with $273 million of this related to non-fuel costs. In addition, we are seeking approval of a new two-way storm cost tracking mechanism, and a new plant in service accounting proposal, as Tom has already discussed. Finally, the pending rate request includes the revenue requirement of Ameren Missouri's new and expanded energy efficiency programs, under the Missouri Energy Efficiency Investment Act, or MEEIA. On page 19, we summarize the Missouri PSC staff's recent recommendations in the pending electric rate case based on our calculation. The staff recommended a $210 million increase, which included $121 million for higher net based fuel costs. The staff's net base fuel costs were $18 million more than Ameren Missouri's request, reflecting updated costs since our initial filing in February. The staff's recommended non-fuel revenue increase of $89 million, which was $184 million less than our request. The primary driver of this $184 million difference was the staff's recommendation of a 9% return on equity, versus our 10.75% request, which accounted for $98 million. On this page, we list other key drivers of this difference, such as -- the exclusion of property tax increases for 2012 over the actual amount paid in 2011; the staff's recommendation that all of the Entergy purchase power refund be credited back to customers over three years; the rejection of a weather normalization adjustment; a lower rate base number primarily due to lower working capital; and a recommendation that we not recover 2011 voluntary separation costs, as well as a number of other adjustments. Turning now to page 20. In other rate case issues, the staff's revenue recommendation incorporated $80 million related to the energy efficiency settlement that was ruled on by the MPSC yesterday. Also, the staff supported continuation of the pension OPEB vegetation management and infrastructure inspection cost tracking mechanism. However, the staff called for changing the FAC sharing mechanism to an 85/15 split rather than the 95/5 split currently in effect. This change in the sharing percentages is similar to what the staff has recommended in past rate cases. Finally, the staff recommended that the Missouri PSC reject our storm cost tracking mechanism, and plant and service accounting proposal. On page 21, we outlined the Missouri Industrial Energy Consumer Group's recommended reductions to our rate request. As you can see, their positions are similar to those of the Missouri PSC staff, though they recommend adoption of a slightly higher return on equity than the staff, at 9.3%. On page 22 -- page 22 completes our discussion of the pending electric rate case in Missouri. The Office of Public Counsel made several recommendations in the case, and we note them on this page. Missouri PSC is scheduled to hold a hearing in the case beginning in late September and continuing through mid-October, with a decision expected in December 2012, and new rates to be effective in January of 2013. Moving now to page 23, here we provide an update on our 2012 through 2014 forward power sales, and hedges for our merchant generation business. Before we move to the updated hedge numbers, at the top of the page we indicate that expected 2012 merchant generation is now expected to be approximately 26.5 million megawatt hours as of mid-2012. This is up approximately 1 million megawatt hours from the estimate we shared with you on our May call, and it reflects increased generation due to the warmer than normal summer weather, driving higher spot power prices and increased utilization of gas fired generation assets. You will also note that for 2012 we have hedged an amount greater than our expected generation, approximately 28 million megawatt hours, and this amount is hedged at an average price of $43 per megawatt hour. The approximately 1.5 million megawatt hours of hedging, in excess of expected generation, is expected to be settled on a profitable basis using purchase power or additional generation to the extent power prices improve. Moving to 2013, we have now hedged approximately 22.5 million megawatt hours at an average price of $37 per megawatt hour. Further, for 2014 we have now hedged approximately 12.5 million megawatt hours at an average price of $38 per megawatt hour. Finally, turning to page 24, here we update our merchant generation segment's fuel and related transportation hedges. For 2012, we have hedged approximately 25 million megawatt hours at $24 per megawatt hour, unchanged from what we communicated to you on the May call. For 2013, we have now hedged approximately 22 million megawatt hours at about $23.50 per megawatt hour, approximately $1 per megawatt hour less than the number we provided in May. For 2014, we have now hedged approximately 14 million megawatt hours at about $23.50 per megawatt hour, also approximately $1 per megawatt hour less than the number we shared with you in May. This completes our prepared remarks.

Questions And Answers

Q - Stephen Byrd {BIO 15172739 <GO>}

Just wanted to touch on the FERC order regarding the dispute of power purchase agreement. Are there any ongoing impacts to earnings that we should be thinking about or is this more of a one time item for this quarter?

A - Marty Lyons {BIO 4938648 <GO>}

Yes, Steven. There aren't any ongoing impacts associated with that. The $0.07 gain we had is a reversal of some negative impacts that we had in prior years as a result of the Entergy charges, those negative impacts had been included in core earnings in the past which is why we reflected this gain in core earnings. That said, we now have a fuel adjustment clause in place in Missouri and there are no ongoing impacts from this settlement.

Q - Stephen Byrd {BIO 15172739 <GO>}

Okay. Understood. And then switching gears to MISO capacity, what are the next steps that we should be thinking about or further steps to come post the FERC order?

A - Marty Lyons {BIO 4938648 <GO>}

I think the thing we are really focused on is this capacity portability issue. And I think the next steps are for in accordance with the FERC's ruling for MISO and PJM to hold discussions about some of the barriers to portability as well as other issues that they have. And then we and other parties will be filing comments with FERC regarding the portability issues. So, those are the ongoing things to watch for.

Q - Stephen Byrd {BIO 15172739 <GO>}

Thank you.

Operator

Paul Patterson, Glenrock Associates.

Q - Paul Patterson {BIO 1821718 <GO>}

The Illinois pollution deferral -- regulatory deferral that you are asking for in terms of implementation, how should we think about the impact of that on your plans where they stand now, I guess, vis-à-vis this issue. There was a press report yesterday that there was a potential plant closures et cetera if this wasn't deferred and I wanted to get some sense as to where things stand?

A - Marty Lyons {BIO 4938648 <GO>}

Sure, Paul. I think what you would be seeing in the press reports would be consistent with things we've talked about on our past couple of calls. Obviously, earlier this year as a result of the drop in power prices amongst other things, we decelerated construction of the Newton Scrubber Project. We talked about the fact that one of the obstacles we had was the Illinois multi-pollutant standard and the ratchet down in terms of SO2 emissions in the 2015 timeframe.

Q - Paul Patterson {BIO 1821718 <GO>}

I understand. I don't mean to make you go over that, I apologize. What I was trying to figure out was, if current -- if you were to get this will this make things -- I mean in other words, we should be under the operate, the guidance and your forecast and everything are under the expectation that we don't have a change. Is that correct? And if you did get the change, how might that change things? Do you follow what I'm saying? Am I understanding that correctly?

A - Marty Lyons {BIO 4938648 <GO>}

I guess so. But there is not, I would say an immediate near term impact as we look out, we are concerned about that ratchet down out in 2015. And to the extent that relief isn't granted from the -- by the pollution control board in the Newton Scrubber is not reaccelerated, then we do face the prospect of plant closures as discussed in our prepared remarks. This is really an impact when we look out to that 2015 timeframe.

Q - Paul Patterson {BIO 1821718 <GO>}

Okay. And then with respect to guidance, I gather if I understand this correctly it is because of the FERC order and because of better than normal weather in the Second Quarter that you guys are raising the guidance, is that correct?

A - Marty Lyons {BIO 4938648 <GO>}

Yes, those were some of the things that we had. You may recall, Paul that after the First Quarter we'd actually lowered our guidance from our regulated entities by about $0.05 on either end of the range. And that's because in the First Quarter we had about $0.10 of negative impact from weather, and so we lowered the guidance $0.05. We've seen an improvement in the weather situation. We are still down year-to-date by about $0.03 on a net basis versus normal. But we did see some positive impact in the Second Quarter from weather. And, we also had the, as you noted, in the positive FERC ruling. Those things allowed us to move the guidance back up $0.05 to where we started the year for the regulated entities.

Operator

Julien Dumoulin-Smith, UBS.

Q - Julien Dumoulin-Smith {BIO 15955666 <GO>}

First on the treasuries and the Illinois formula [ph] rates, I noticed that you mentioned 3% here. Is that still using the blue chip average? And then, secondly, did that have sort of a mark-to-market impact in the Second Quarter and what was that? I apologize if I missed that in your prepared remarks.

A - Marty Lyons {BIO 4938648 <GO>}

That's fine Julien, the 3% reflects the actual experience in terms of 30 year treasuries for the first half of the year as well as blue chip forecast as of July. So it's really the average for the year which is what's included in the ROE. So that 3% is what's baked into the guidance. In terms of the way to think about that, about every 10 basis points or so is about $0.005 per share. About a 30 basis point move is a $0.015 to $0.02 when you're thinking about the impact of something like that. Overall, I wouldn't say there was a mark-to-market. The regulatory asset that we recorded at the end of the First Quarter was unchanged at the end of the Second Quarter as it related to that business.

Operator

Michael Lapides, Goldman Sachs.

Q - Michael Lapides {BIO 6317499 <GO>}

On Illinois Marty, just want to make sure I follow. The rate base level declined from 2012 in your filing the 2013 little bit over right around $100 million to $120 million some odd. Can you just walk us through the puts and takes? Meaning, net capital additions minus normal course depreciation and then minus bonus depreciation just so we can think through the give and take and then think about how this impacts post 2013?

A - Marty Lyons {BIO 4938648 <GO>}

Michael, I don't have a full reconciliation to walk you though. Maybe something you can follow up with Doug after the call. You highlighted one of the drivers for that decrease, the biggest is really that bonus depreciation which has been included. Of course, that's been reflected in the guidance. I think what you have seen in some of these cases that we have pending, is folks arguing that the cumulated depreciation should be included in the rate base. And certainly for this year in terms of the way we have been forecasting our earnings and forecasting our rate base, we have included the deferred tax update from bonus depreciation in there, so that's a big driver.

Q - Michael Lapides {BIO 6317499 <GO>}

Thank you.

Operator

Andy Bishop, Morningstar.

Q - Andy Bishop {BIO 20466271 <GO>}

I have a clarification question on the FAC order. If I understand it correctly you took a $18 million charge in 2011. No charge in 2011 and then you'd reversed the charge in 2013 pending the favorable opinion. Is that correct?

A - Marty Lyons {BIO 4938648 <GO>}

That could be. Don't want to speculate on the outcome in '13. But yes we took a charge last year of about $0.05 as noted on the call there is still about $25 million or $26 million pending before the Missouri Public Service Commission that we expect them to rule on later this year. And then we will see how these court appeals play out. Obviously we took a charge because of the last year because of the commission's decision and of course we flowed those moneys back through the FAC. If at some point that commission decision is reversed one way or another, and ultimately we are able to collect those moneys, at that point it would become a gain.

Q - Andy Bishop {BIO 20466271 <GO>}

Thank you, so much.

Operator

Kevin Fallon, SIR Capital.

Q - Kevin Fallon {BIO 19872493 <GO>}

Within your 2012 core earnings guidance of $2.25 to $2.55, what is the amount of parent company drag when you are not allocating nonrecourse debt interest expense related to that?

A - Marty Lyons {BIO 4938648 <GO>}

I don't know that what the parent company drag is typically what we've done with our debt for the most part is allocated those costs out. The parent company debt that exists, the $425 million of debt, you know for the most part those interest charges actually get allocated out to the merchant segment and a senior [ph] supporting that merchant segment. So while there the $425 million is an obligation of Ameren Corporation, the debt is being seen as supporting capital expenditures made at the merchant segment over time. Primarily, well I shouldn't say primarily, really at AERG which is a non-registrant so we allocate those interest costs out to that segment.

Q - Kevin Fallon {BIO 19872493 <GO>}

There is a much larger component of nonrecourse debt that you also book within the merchant generation section that would go away if you walked away from those businesses. Just trying to understand if you separated from the merchant generation businesses, what are the ongoing expense that you would have at the holding company level to offset against the regulated utilities?

A - Marty Lyons {BIO 4938648 <GO>}

In terms of the debt, there is $825 million or so of debt at Ameren Energy Generating that is nonrecourse debt. That interest expense is allocated to Ameren Energy Generating and AER and then there's the other $425 million up at Ameren Corp. And again, that's an Ameren Corp obligation and the interest expense is allocated down to that segment, Ameren Energy Resources.

Operator

David Paz, Bank of America.

Q - David Paz {BIO 16573191 <GO>}

I was wondering, following the agreement on MEEIA, what are the prospects of settlement in your ending Missouri rate case?

A - Marty Lyons {BIO 4938648 <GO>}

David, I think maybe I will let Warner Baxter take that one.

A - Warner Baxter {BIO 1858001 <GO>}

David, how are you doing?

Q - David Paz {BIO 16573191 <GO>}

Good Warren, how are you doing?

A - Warner Baxter {BIO 1858001 <GO>}

I'm terrific, thanks. With regard to the settlement, as you know we've in the last several rate cases we have not really come together in a comprehensive basis to settle the entire rate case. And that's due to several reasons, largely due to the fact that we have several part of those cases and certainly several issues to resolve. But historically, we have been able to take several issues and resolve those in a partial settlement and then take ultimately fewer issues to the commission. Having said all those things, certainly the prospects of settlements are always there should the discussions be fruitful, and that they are fruitful we will be happy to engage in those discussions to see if we can find something that makes sense. So, I can't predict the outcome but certainly if the opportunities arise that make sense for us we will move forward with that.

Q - David Paz {BIO 16573191 <GO>}

Great. And just one question regarding your merchant segment. What price level, Marty, are you looking for or you would need to avoid moth balling the two of the three unscrubbed coal plants?

A - Marty Lyons {BIO 4938648 <GO>}

David, there's not I'd say, a specific price level that I'd point to that would cause us to avoid that. I think what you are really asking is there a certain price level at which the Newton Scrubber would be reaccelerated. And consistent with what we said on prior calls, I think that we've estimated that if we reaccelerated we'd probably need something like 20 months or 24 months of construction time to have that scrubber in service. So we continue to have some time to watch how things develop. But it's not just power prices, certainly we watch power prices, when I think of power, I guess I should say, I think of energy and I think of capacities. We are watching energy prices, capacity prices, developments in terms of federal environmental regulations and the like. So, there will be a host of factors but I can't point to a specific price that would be sort of a threshold.

Operator

Paul Patterson, Glenrock Associates.

Q - Paul Patterson {BIO 1821718 <GO>}

I just wanted to follow up so I understood the guidance. It looks like there is about $0.07 of extra weather in the Second Quarter and $0.07 associated with the -- $0.07 for the weather and $0.07 of FERC, which is about $0.14. And you mentioned how you had re-adjusted your numbers previously. Is there anything that we should think about that would lower the number, so that we only have the $0.05 increase in guidance, or is there something -- or are you guys just being conservative?

A - Marty Lyons {BIO 4938648 <GO>}

Yes. So you are right. The numbers you gave out are right. The Q2 weather versus normal was about a plus $0.07. Then the FERC agreement was another $0.07 that you are absolutely right. I think in terms of again why $0.05? I think that again, we are still down weather wise because we had a $0.10 drag in the First Quarter. We only reduced the regulated guidance by about $0.05. We have picked up $0.07 of that, yes in the Second Quarter, but are still down net $0.03 year-to-date due to weather. As asked on a prior call we've had about a 30 basis point drop in the ROE's in Illinois. Which again as I said earlier, is probably a $0.015 to $0.02 of earnings. And then I think one other thing, Paul, that we mentioned on the call is when we strip out weather, we are seeing pretty flat load growth in terms of residential commercial year-to-date. We did at the beginning of the year and frankly continue to expect as we look to the second half of the year, to see some growth in those categories. Year-to-date we haven't seen any, now weather normalization obviously is not an exact science. We've had pretty good extremes both in terms of the winter months and the spring, summer months year-to-date. Sometimes those can cause variations, but we are seeing things pretty flat year-to-date. Those are some of the factors. The other thing I would say though Paul, that we mentioned, is that the July weather has been extremely warm and continues to be extremely warm, even this week. None of the impacts of that favorable weather in July have been reflected in the guidance that we've provided.

Q - Paul Patterson {BIO 1821718 <GO>}

That's great. Just one other that leads me to my second question which is have you guys had any new peaks? Have you found any change in peak demand? You mentioned the sales growth being kind of flattish and I think that's what a lot of people have seen -- or even actually down weather normalized. Just in terms of you had amazingly hot weather I think in the midwest, at least it looked like it was from reports. What are you guys seeing in terms of peak demand?

A - Marty Lyons {BIO 4938648 <GO>}

Yes, I should have brought some exact data so I don't. I can tell you that while we had some very strong demands, I think we are still down from some of the peaks we saw a couple years ago. Maybe I will ask somebody else to comment on that quickly.

A - Maureen Borkowski {BIO 7081192 <GO>}

This is Maureen Borkowski. On a transmission system basis, we did set a new all time peak on July the 25 of, I forget the exact number, I think it was 18,588 megawatt's. Based on the two individual Companies, Ameren Illinois did set a new all time peak on that same day. Ameren Missouri has not yet exceeded its all time peak which was in 2007.

Operator

Brian Taddeo, Gleacher and Company.

Q - Brian Taddeo {BIO 5818230 <GO>}

First question is with regards to your request for environmental variance in Illinois with the hearing having taken place yesterday, you -- what's the next step here? Is there another hearing date or is the next thing we will hear is a ruling coming out of the board?

A - Marty Lyons {BIO 4938648 <GO>}

There won't be another hearing set, and we basically would expect to see a decision by the Pollution Control Board deadline September the 20.

Q - Brian Taddeo {BIO 5818230 <GO>}

Have they given you any -- have you gotten any guidance or input in what their major focus is? You mentioned all the different parties and their different views, but have they given you any idea what of what they are focused on in terms of making their decision?

A - Marty Lyons {BIO 4938648 <GO>}

No. Yesterday I think the public hearing was well attended. All five of the members of the Pollution Control Board were in attendance. I think they were very attentive and I think they heard from folks that spoke, I would say on behalf of our petition, folks that are located in our service territories that would -- that spoke of the potential economic and personal impact of the variance. And of course there were citizens group there who spoke in opposition. So, what the pollution control board there to do again is to balance both environmental concerns with economic concerns. And they heard testimony on both sides. Ultimately, really the only parties to this proceeding are ourselves and the IEPA. As noted on our call, the IEPA has taken a neutral stance on this and sees our petition as being environmentally beneficial. And that's our view as well. So we looked to the Pollution Control Board again to balance the economics with the environmental mandate.

Operator

Julien Dumoulin-Smith, UBS.

Q - Julien Dumoulin-Smith {BIO 15955666 <GO>}

First as you just alluded to for the net positive benefits. I know it's IEPA here, but I kind of wanted to get a sense how is it actually a net positive? It's just because you are accelerating some of the reductions from 2015 forward, and that sort of offsets what would have happened in the back half of the decade? Is that the right way to think about it?

A - Marty Lyons {BIO 4938648 <GO>}

That is a good way to think about it Julien.

Q - Julien Dumoulin-Smith {BIO 15955666 <GO>}

All right. And then secondly on capacity portability, what could this eventually mean? Just trying to think about an ideal scenario. This is all of your capacity, partial, is this just about getting some transfer rights recognized? There are a number of different iterations I could see coming out of this. I want to get your say.

A - Marty Lyons {BIO 4938648 <GO>}

I think that's probably true. There probably are a number of different iterations that could come out of it. But certainly I think to the extent that we have capacity and we have got -- there's available transmission to get out of MISO and into PJM. We think we ought to be able to sell that capacity into PJM. Whether that's a percent of our fleet ultimately would be available to do that. I don't know off hand. But I think it could be a number, as you said, a number of outcomes there.

A - Doug Fischer {BIO 16481971 <GO>}

Operator, this is Doug Fischer, we have time for one more question.

Operator

Michael Lapides, Goldman Sachs.

Q - Michael Lapides {BIO 6317499 <GO>}

Marty, easy one here, can you just walk us through in the first half of 2012, what are items that are still included in ongoing EPS, but may not actually happen next year? Meaning kind of like the FERC item, the $0.07 benefit from the FERC item that's in ongoing EPS. I'm just trying to think about whether it's storm related or anything else, but is left for accounting reasons and ongoing EPS but may not actually be recurring 12 months from now.

A - Marty Lyons {BIO 4938648 <GO>}

Sure, Michael. I think that we've tried to list the major ones on slide 3. I guess those are mostly related to Q2 and maybe I'd focus you back on our Q1 slides as well. We had a similar slide for Q1. But you do see the FERC order there. We had the absence of the fact [ph] charge from last year. And the storm costs from last year. As I recall from the First Quarter, too though, we picked up I think a couple of cents of impact in Ameren Illinois because of contributions that we made at the start of the Illinois rate filing. So, again I'd point you back to those First Quarter slides. I think we had a negative in the First Quarter that would not be repeating again next year. And then, I think as you look to next year, I think some of the things to think about are just the resolution of the Missouri rate case later this year. Next year we will have a Calloway outage where there was no Calloway outage this year. And those will be some of the drivers as well as what happens with 30 year treasuries. And it affects Illinois. And our continuing due to deploy capital as we've laid out. Those are some of the impacts to be thinking about.

Q - Michael Lapides {BIO 6317499 <GO>}

Got it. Okay. Thank you, Marty, thank you. Much appreciated.

A - Doug Fischer {BIO 16481971 <GO>}

This is Doug Fischer. Thank you for participating in this call. Let me remind you again that this call is available for one year on our website. You may also call the contacts listed on the release. Financial analyst inquiries should be directed to me, Doug Fischer, or to my associate Matt Thayer. Media should call Brian Bretsch. Our contact numbers are on the news release. Again, thank you for your interest in Ameren.

Operator

This concludes today's teleconference, you may disconnect your lines at this time, and we thank you for your participation.