COMMENTS ON THE 2012 PROCUREMENT PROCESS PURSUANT TO SECTION 16-111.5(o) OF THE PUBLIC UTILITIES ACT

PRESENTED TO

THE ILLINOIS COMMERCE COMMISSION

by

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AS THE COMMISSION'S PROCUREMENT MONITOR

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I. INTRODUCTION

Boston Pacific Company, Inc. ("Boston Pacific") appreciates the opportunity to submit these comments in response to the Illinois Commerce Commission's (the "Commission's") request for comments concerning the 2012 Electric Procurement Events which were held on behalf of Commonwealth Edison Company (ComEd) and Ameren Illinois Company (Ameren).[1]

Boston Pacific served as the Commission's procurement monitor for the nine requests for proposals (RFPs) issued this year by ComEd and Ameren. These include four Rate Stability RFPs held in February to fulfill the requirements of Senate Bill 1652, which became law in October 2011 and required ComEd and Ameren to solicit energy and RECs for the four-year seven-month period from June 2013 through December 2017.[2] The remaining five RFPs were consistent with those held every year since 2008 to purchase energy, capacity and RECs.[3] As required by the Illinois Public Utilities Act (hereafter, along with the Illinois Power Agency Act, collectively the "Act"), after each Bid Day Boston Pacific provided confidential reports to the Commission that presented the procurement results and assessed bidder behavior and compliance with the procurement processes and rules. We recommended that the Commission accept the results of the nine RFPs.

The bases for our recommendations were as follows. First, the RFPs were successful in acquiring the vast majority of the targeted quantities. Second, in the context of the Act's requirement to assess bidder behavior, we found no evidence of collusive or otherwise anti-competitive behavior. Third, in the context of the Act's requirement to assess whether the RFPs were run in compliance with the rules, we concluded that these RFPs were run by the procurement administrators in compliance with all Commission-approved rules.

We structure our comments by first providing a summary of the results of these RFPs, commenting on bidder behavior, and assessing the RFPs' compliance with the rules (Section II). We then discuss the implications of the recent increase in customer switching on these RFPs; we consider this increase to be the most significant event this year (Section III). Finally, we provide design considerations with regard to the credit requirements of the RFPs and next year's requirement to procure distributed renewable energy generation (Section IV).

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[1] *Public Notice of Informal Hearing (Request for Comments) Concerning the 2012 Electric Procurement Events Which Were Held On Behalf of Commonwealth Edison Company and Ameren Illinois Company*, Issued 5/17/2012.

[2] These are: (1 & 2) Ameren's and ComEd's RFPs for around-the-clock energy (held on February 10, 2012), and (3 & 4) Ameren's and ComEd's RFPs for RECs (held on February 16, 2012).

[3] The five standard Spring RFPs include: (1) Ameren's RFP for Capacity (held on April 5, 2012), (2 & 3) Ameren's and ComEd's RFPs for Energy (held on April 26, 2012), and (4 & 5) Ameren's and ComEd's RFPs for RECs (held on May 10, 2012).

II. SUMMARY OF RFP RESULTS

A. Rate Stability Energy RFPs

ComEd and Ameren solicited around-the-clock (24 hours per day) energy for the four-year seven-month period from June 2013 through December 2017. ComEd solicited 450 MW in a single product that covered the entire period, and was successful in procuring all that was sought at prices below the approved benchmarks. Rather than soliciting bids under a single product, Ameren solicited 650 MW under five separate products. Each product represented a separate period of time: (a) June 2013 to May 2014, (b) June 2014 to May 2015, (c) June 2015 to May 2016, (d) June 2016 to May 2017, and (e) June 2017 to December 2017. Ameren successfully procured all the targeted quantities for the first two time periods or "products:" June 2013 to May 2014 and June 2014 to May 2015. However, the targets were not met for the remaining three products. For the third period, June 2015 to May 2016, just 200 MW out of the 650 MW sought were successfully procured. For the last two periods, June 2016 to May 2017 and June 2017 to December 2017, none of the sought-after 650 MW was procured.

For ComEd, the weighted average winning price was $32.57/MWh. This price will escalate at 2.5% per year, yielding a weighted average price of $34.09/MWh for the period from June 2013 through December 2017. For Ameren, the weighted average winning price for its first period was $29.51/MWh. For the second and third periods the weighted average winning prices were $31.44/MWh and $33.62/MWh, respectively. The total value of contracts for both RFPs was $1.0 billion.

When less than 100% of the sought-after quantities are procured due to insufficient supplier participation or due to a Commission rejection of the procurement results the Act instructs that "the procurement administrator, the procurement monitor, and the Commission staff shall meet within 10 days to analyze potential causes of low supplier interest or causes for the Commission decision." If changes are identified that would likely result in increased supplier participation, or that would address concerns causing the Commission to reject the results, the procurement administrator may implement those changes and rerun the RFP within 90 days. Commission Staff, procurement administrators, and Boston Pacific, as procurement monitor, understand this provision to mean that, whenever any of the targets are not met, all parties are to meet to determine if an additional RFP should be held to procure the unmet targets. All parties met and decided that Ameren should not issue another RFP but, rather, attempt to procure the unmet targets through the energy RFPs that will be held in future years.

B. Spring 2012 Energy RFPs

ComEd and Ameren also acquired energy products to meet all or part of each utility's energy need for the three service years that cover June 2012 through May 2015. This year significantly lower quantities of products were solicited when compared to the RFPs held in past years. This was due to significant reductions in each utility's projected load due to customer switching, and the fact that the projected load was largely met or exceeded by energy purchases from past procurements.

Ameren only solicited energy for several months within the first service year (2012-13).[4] Ameren's average weighted winning prices were $32.39/MWh for peak hours and $24.94/MWh for off-peak hours. ComEd only solicited energy for June and July of the first service year (2012-13) and for several months within the third service year (2014-15). ComEd's average prices for the first service year were $36.39/MWh for peak and $22.83/MWh for off-peak. ComEd's average prices for the third service year were $45.65/MWh for peak and $29.99/MWh for off-peak.

C. Ameren's Capacity RFP

Under the rules of the Midwest Independent Transmission System Operator (MISO) Ameren is required to secure specific capacity resource volumes to meet or exceed its monthly Resource Adequacy Requirement (the monthly peak load forecast plus its planning reserve margin). To comply with MISO's requirement, Ameren solicited monthly Planning Resource Credits (PRCs) for the service year starting June 2012 through May 2013. Due to pending changes to MISO's capacity construct, rather than PRCs, Zonal Resource Credits (ZRCs) were procured for service years June 2013-May 2014 and June 2014-May 2015. PRCs and ZRCs each represent one megawatt of capacity that qualifies to satisfy Ameren's Resource Adequacy Requirements under MISO's rules.

Ameren successfully procured a significant share (97.7%) of the targeted quantities of PRCs and all the targeted quantities of ZRCs. July 2012 was the only month in which the target was not met. It fell short by 350 PRCs out of the 1,980 PRCs being solicited. The weighted-average price of the PRCs procured for the 2012-2013 period was $34.17/MW-month. The average price of ZRCs procured for 2013-14 and 2014-2015 was $3,698/MW-year and $7,642/MW-year, respectively. The total value of the contracts awarded was about $15 million.

ZRCs were procured for the first time this year in anticipation of FERC's approval of significant changes being proposed to MISO's resource adequacy construct. The changes

[4] Ameren solicited on-peak energy for 5 months and off-peak energy for 4 months.

include establishing seven local resource zones within MISO for which resource adequacy must be met, and moving to an annual construct instead of the current monthly construct. The changes ended up being conditionally approved by FERC on June 11, 2012 and are on track to becoming effective for the service year that begins on June 1, 2013. Going forward, load serving entities will meet their planning reserve margin requirements by participating in planning resource auctions that will determine the price of capacity in each load zone, by self-scheduling their planning resources, or through certain opt-out procedures. We note that if Ameren chooses to meet its planning requirements through the auctions there may not be a need to hold this separate capacity RFP in the future. ComEd does not hold its own capacity RFP because it procures capacity instead from PJM-administered markets. This was deemed appropriate because capacity prices are determined by a competitive bid process administered by PJM.

Finally, we note that, in its 2011 Long-term Resource Assessment, MISO states that there is uncertainty about pending regulations from the Environmental Protection Agency (EPA). According to MISO, the passage of these regulations could lead to increased unit retirements throughout the MISO region, quickly eroding reserve margins from their projected levels. MISO indicates that approximately 3,000 MW of coal generation could be retired by 2015 under a scenario where natural gas prices are $4.5/MMBtu and no carbon emission price or tax is assumed. The coal retirements could grow to 12,600 MW in a scenario where a carbon emission price or tax is $50/ton. If no replacement capacity is identified, then the system reserve margin could decrease from 27% in 2012 to 19.9% in 2016 under the first scenario and to 10.1% (below the 17.4% reserve requirement) under the second scenario. For 2021, reserve margins could decrease to 16.2% under the first scenario and to just 6.9% under the second scenario.[5]

D. Rate Stability REC RFPs

Ameren and ComEd solicited RECs for five compliance periods spanning from June 1, 2013 to December 31, 2017.[6] Ameren successfully procured all 2,053,837 RECs it solicited while ComEd procured 98.6% of the 2,774,591 RECs it solicited. While ComEd procured all targeted RECs for the first four compliance periods, it only met 88% of the last period's target. Average winning prices ranged from $2.38 to $6.07 for Ameren and from $1.28 to $2.50 for ComEd across the five periods being solicited. The average winning prices for wind RECs ranged from $1.13 to $4.92 for Ameren and from $1.27 to $3.38 for ComEd. Winning prices for Solar RECs were much higher; they ranged from $82.49 to $96.92 for Ameren and from $60.04 to $74.49 for ComEd. Note that for solar RECs, the higher average winning prices for Ameren

[5] MISO 2011 Long-term Resource Assessment

[6] The five compliance periods are: a) June 2013 to May 2014 (Period 1), b) June 2014 to May 2015 (Period 2), c) June 2015 to May 2016 (Period 3), d) June 2016 to May 2017 (Period 4), and e) June 2017 to December 2017 (Period 5).

compared to ComEd are mainly due to the purchase of more solar RECs. The total value of contracts awarded under both RFPs was about $12.8 million.

Finally, we note that almost all RECs procured for Ameren were from Illinois and Adjoining states (over 99% in each period). This was also true for the first three periods in ComEd's RFP. For the last two periods in ComEd's RFP, only 35.4% and 0% of RECs were procured from Illinois and Adjoining states, with most RECs being procured from lowered-price RECs from "other states."

E. Spring 2012 REC RFPs

These two REC RFPs brought Ameren and ComEd into compliance with the Illinois Renewable Portfolio Standard (RPS) laid out in the Act. The Illinois RPS required Ameren and ComEd to procure from cost-effective renewable energy resources at least 7% of their electricity supply to serve the load of eligible retail customers for the period June 1, 2012 through May 31, 2013. The utilities had already procured roughly half of the RECs needed to meet the 7% requirement through the 20-year long-term renewable energy RFPs that were held in 2010.[7] The goal of the current REC RFPs was to procure the additional quantities of RECs that were needed for the 2012-2013 service year. This goal was achieved for both utilities.

Ameren successfully procured its target of 523,376 RECs and ComEd successfully procured its target of 1,335,673 RECs. All winning RECs were from Illinois and its adjoining States. The cost to procure RECs was about $0.6 million for Ameren and $1.2 million for ComEd. These costs are substantially lower than the budgets established for these RFPs, which were about $13 million for Ameren and $17 million for ComEd. As required by the Act, the budgets were established to limit the anticipated effect of REC costs on rates to about 2% of total eligible customer energy costs. Wind RECs were acquired at average prices of $0.80/REC for Ameren and $0.88/REC for ComEd. These prices are lower than what we saw last year, when wind REC prices were $0.99/REC for Ameren and $1.05/REC for ComEd. Solar RECs were acquired at an average price of $79.74/REC for Ameren, and no solar RECs were acquired for ComEd.

F. Comments on Bidder Behavior

In the context of the Act's requirement to assess bidder behavior, we found no evidence of collusive or otherwise anti-competitive behavior. We examined the competitiveness of the RFPs with three metrics: (1) the number of bidders and winners, (2) the ratio of products offered to those solicited, and (3) an analysis of winning shares. We can only comment on the number

[7] The 2010 Long-Term Renewable Energy and Renewable Energy Credit RFPs (2010 LT RFP).

of winners, which is the only information made public. There were 7 winners for the Energy Rate Stability RFPs, 13 winners for the REC Rate Stability RFPs, 9 winners for Ameren's Capacity RFP, 5 winners for the Spring 2012 Energy RFPs, and 10 winners for the Spring 2012 REC RFPs.

A review of the publicly announced winners for these RFPs shows that many bidders participated in multiple RFPs. Thirteen out of the 28 winners were listed as winners in 2 or more RFPs. Furthermore, 23 of this year's 28 winners had also won some share in at least one of the RFPs that have been held since 2008. This high number of return bidders is a sign that the process is viewed by bidders as being fair and transparent.

G. Comments on Compliance with the Rules

In the context of the Act's requirement to assess whether the RFPs were run in compliance with the rules, Boston Pacific concludes that these RFPs were run by the procurement administrators in compliance with all Commission-approved rules including: communication among the procurement administrators, bidders and the utilities; product types solicited; the use of standard contracts; the calculation and use of market-based benchmarks; and procedural requirements such as providing bidders an opportunity to comment on contracts and credit-related documents.

The RFPs also complied with those specific changes that were either specified in the Act or approved by the Commission in this year's Final Order:

First, the utilities complied with the Order's instruction to submit revised load forecasts between March 1 and 10 of this year. The most noteworthy aspect of these RFPs was that there was a significant decrease in the quantities to be procured since the time the Order was approved. We discuss this in Section III.

Second, the product types and quantities for Ameren's Capacity RFP were in compliance with the Commission's order to procure monthly PRC capacity products for the 2012-2013 service year, and annual ZRC capacity products for the 2013-2014 and 2014-2015 service years. Two standard contracts were developed based on the Edison Electric Institute (EEI) Master Purchase and Sale Agreement Version 2.1. One contract applied to the winners of PRCs for the first service year, while the other to the winners of ZRCs for the second and third service years.

Third, the REC budgets complied with a significant change specified in the Act. The Act required that, starting this year, the budgets also include funds collected from the utilities' retail customers who are on an hourly pricing tariff. The utilities began collecting money from these customers starting June 1, 2010. Adding these funds meant that this year Ameren's budget was

increased by $424,440 and ComEd's by $1,499,113. However, none of these additional funds were used because the utilities were able to purchase all REC targets at costs that were significantly lower than the allowable budgets. While the Act says that the budgets are to be increased by the ACP amounts collected from hourly customers, it does not specifically say that the REC quantities to be procured should be increased. **We suggest that the IPA clarify for next year if (a) additional RECs should be procured with the funds collected from hourly customers, or if not (b) should any unused funds be credited back to customers.**

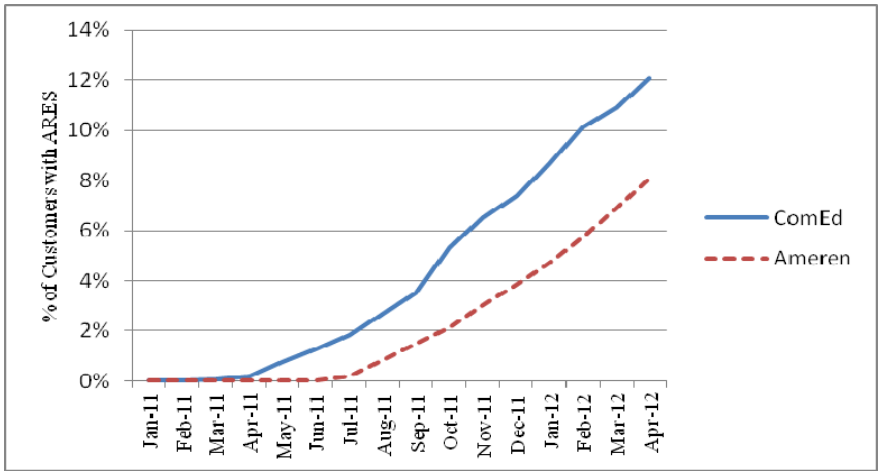
Fourth, for the REC RFPs, the product types and REC priorities were adjusted this year to be in compliance with the Act's requirement for a solar target starting in June 2012. The Act requires that solar RECs be given equal priority to wind RECs. For background, legislation[8] was passed in 2010 that specifies a solar renewable energy target of 6% for 2015, and further instructs that there be a "ramp up" period between 2012 and 2015, beginning with a target of 0.5% in 2012. The solar target was first applied in the 2010 RFPs for long-term renewable energy.

[8] Public Act 096-1437, effective August 17, 2010.

III. IMPLICATIONS OF CUSTOMER SWITCHING FOR THESE RFPs

A substantial number of ComEd and Ameren's residential customers have switched to Alternate Retail Electric Suppliers (ARES) since March 2011. Figure 1 shows that, while in January 2011 there were practically no residential customers that had switched to an ARES, by April of 2012 around 12% of ComEd's and 8% of Ameren's residential customers had switched. One of the reasons for switching is that ARES have been able to offer lower prices to customers than the utilities. This is because the utilities' prices include pre-existing contracts, some of which were entered into several years ago when prices were much higher than what they are today.

Figure 1 – Percent of ComEd and Ameren's Residential Customers who Switched to an ARES



Source: Monthly customer switching reports filed by Ameren and ComEd

We expect significant additional switching to occur because of municipal aggregation. On March 20, 2012, referendums on aggregation were held in a large number of municipalities and the majority approved a switch to ARES.[9] Ameren and ComEd estimated the impact of these referendums in load forecasts that were prepared in March.[10] The March load forecasts

[9] For background, starting in January 1, 2010 the IPA Act has allowed municipalities to aggregate residential and small commercial retail electrical loads and purchase electricity for those loads. A referendum is required if a municipality wants to conduct a load aggregation program in which all of its residents are automatically switched to an ARES, unless they expressly "opt-out." On the other hand, a referendum is not required if the municipality conducts an "opt-in" load aggregation program. A significant number of municipalities chose to conduct an "opt-out" load aggregation program, and thus held referendums on March 20, 2012.

[10] At the time the Commission issued its Order in December 2011, there was still much uncertainty about the effects that referendums would have on the quantities to be solicited. Therefore, the Order instructed Ameren and ComEd to submit revised load forecasts between March 1 and 10 of this year.

reflected a substantial decrease in load due to customer switching when compared to the load forecasts that had been submitted in the Fall of 2011. For the first service year (June 2012 – May 2013) Ameren's load forecast fell by 20% and ComEd's fell by 18%. After ballots were cast on March 20, the utilities confirmed that the results of the referendums were that a great number of municipalities opted to switch to ARES and thus, their revised forecasts were still reasonable.

The quantities of energy and capacity to be procured through the Spring RFPs were dramatically decreased because of the significant load reductions observed in the March 2012 load forecasts. For the first service year (June 2012 through May 2013), the quantity of peak energy products to be procured by Ameren decreased from 4,900 MW to 700 MW, and for ComEd from 2,250 MW to 700 MW. Similarly, the off-peak quantities decreased from 4,050 MW to 1000 MW for Ameren, and from 1,600 MW to 450 MW for ComEd. There were also significant decreases in the quantities to be procured for the second (2013-14) and third (2014-15) service years. The decreases in target quantities for the second and third service year were due not only to the revised load forecasts, but also to the fact that most of the energy for those periods had been procured through the Rate Stability RFPs. The updated utility forecasts also showed a significant decrease in the amount of capacity to be procured through Ameren's Capacity RFP. For the first service year the monthly quantities to be procured decreased by an average of 32%. The quantities to be procured for the second service year (June 13- May 14) and third service year (June 14- May 15) decreased by 22% and 23%, respectively.

We expect that only small quantities of energy and capacity will need to be procured through next year's Spring RFPs. There is even a chance that it may not be necessary to hold these RFPs. We say this for two reasons. First, as explained above, we expect that customers will continue to switch in significant amounts to ARES, resulting in a decreasing load that needs to be filled. Second, there is already an existing oversupply of energy for a number of months over the next three service years. The oversupply of energy has resulted from the combined effects of lower load projections and the fact that some of the need was already procured through previous RFPs and mandated swap contracts.[11] Over the 36-month period starting June 2012, ComEd exceeds its projected need for 21 on-peak months and 22 off-peak months. Similarly, Ameren exceeds its projected need for 10 on-peak months and 14 off-peak months over the same time period. This means that, unless actual demand increases so that these latest projections end up being exceeded, both utilities will have to sell excess energy into the spot markets, possibly at a loss to ratepayers.

[11] The existing contracts include: (a) mandated swap contracts, which procured 1,000 MW up to 3,000 MW of around-the-clock energy from ComEd through May 2013, and 400 MW to 1,000 MW from Ameren through December 2012; (b) energy procured through the 2010, 2011 and 2012 energy RFPs; (c) energy procured through the recent rate stability RFPs, and (d) a small amount procured through the 2010 long-term renewable resources RFP.

Customer switching has added a significant degree of unpredictability to load forecasting and has introduced a high level of complexity when determining the optimal quantities of products to be procured through the Spring RFPs. In the past, the utilities have used the Spring RFPs to purchase energy and capacity products for a three year period. Purchasing products for three years out has been viewed by the IPA as the best way to achieve price stability for eligible customers. Specifically, the IPA has determined that price stability can be best achieved by procuring 100% of the first year's need, 70% of the second year's need, and 35% of the third year's need. The need is determined based on load forecasts that are submitted by the utilities and that form part of the procurement plan that the Commission approves in its Final Order. In the past, the utilities have developed load forecasts that reasonably predict load demand three years out. These load forecasts were fairly stable from year to year and varied primarily by the expected increases or decreases in the amount of energy that customers would consume. Customer switching has introduced significant unpredictability to these load forecasts. This is because going forward the utilities must also factor into the forecasts an estimation of the number of customers who will switch to ARES.

The unpredictability introduced by customer switching poses a risk to ratepayers in that they may end up paying higher costs to obtain energy to the extent that utilities end up over- or under-purchasing energy through the Spring RFPs. For example, if the actual load ends up being lower than what was forecasted (e.g. customer switching is higher than anticipated), the utilities would have over-purchased energy and would have to sell the excess energy to the spot market. It is likely that this excess energy would be sold at a loss because lower demand usually results in low spot energy prices. On the contrary, there could also be a case in which actual demand is higher than what was forecasted. This would happen if customers switch back to the utilities. This could happen at times when energy prices start to increase and the utilities are able to offer better prices than ARES because they have previously locked down lower-priced energy contracts. In this case, the utility would have procured less energy than needed and would have to purchase the supplemental energy through the spot market. It is likely that in this situation spot market prices will be high because of the increase in demand.

We see three ways in which the risk of over- or under- procuring may be mitigated. First, the Commission could order the utilities to submit an updated load forecast in March that would be used to update the quantities to be procured (which would have originally been based on a load forecast that was developed during the previous Fall). Such an update was required by the Commission this year and, as indicated above, resulted in a substantial decrease in the quantities to be procured. Second, the IPA could procure less by lowering the targets to be hedged over the next three service years. As indicated above, the IPA attempts to procure 100% of the first year's need, 70% of the second year's need, and 35% of the third year's need. Third, RFPs could be held more frequently. For example, procurements could be held twice during the year, once

each half-year period. The risk of over or under-procuring would decrease because there would be more frequent load projections from which to derive the quantities to be procured. We view the third option as one that will not likely be implemented because of the added complexity of introducing additional RFPs each year.

IV. RECOMMENDATIONS AND COMMENTS ON CREDIT REQUIREMENTS AND DISTRIBUTED GENERATION

A. Credit Requirements

Since 2008, the procurement administrators, Staff, utilities, and procurement monitor have made efforts to harmonize standard contracts and credit requirements across the RFPs. The most significant areas that are important to bidders have also been addressed through the process of reviewing comments that are submitted by bidders. One noteworthy aspect is that this year, when given a chance to suggest changes to the standard contracts, very few bidders chose to do so. We attribute this to the fact that by now these contracts have become highly standardized. Following are two suggestions to further harmonize the RFP's credit requirements.

We recommend that common forms of pre-bid letters of credit be used across all RFPs. The pre-bid letters of credit are required for each RFP to: (a) ensure that those bidders who win will follow through with executing the contracts and post the necessary credit requirements, (b) provide security to the utilities in the event a bidder makes a misrepresentation on its bid or application or violates any RFP rules, (c) provide security to the utilities in case the bidder discloses information relating to its proposal before the ICC has rendered its decision on the results of the procurement. Over the years the pre-bid letters of credit used by ComEd and Ameren have been harmonized to a very large extent. However, an additional constructive step would be to develop a single format that can be used across both utilities. We see several benefits in doing this. First, this will further the goal of standardizing the RFPs. Second, this would allow bidders who participate in multiple RFPs to present a single format to their banks which would simplify the process of obtaining the required letters of credit. Third, bidders would only need to submit a single set of comments or proposed changes, rather than having to submit them under multiple RFPs. Fourth, this will ensure full consistency between the optional changes (acceptable modifications) across utilities.

We also recommend that, if possible, post-bid letters of credit be further standardized across both utilities. The post-bid letters of credit provide assurance to cover the utility's exposure under the contracts. Over the years these have also been harmonized to a very large extent across Ameren and ComEd. The most significant change to the contracts this year was that NERA presented ComEd bidders with two standard forms of the post-bid letter of credit, instead of one. The main purpose was to have one version that conforms to the "Uniform Customs and Practice for Documentary Credits, 2007 Revision, International Chamber of Commerce Publication No. 600" and the other version that conforms to the "International Standby Practices (ISP98), International Chamber of Commerce Publication No 590." In the past, through the acceptable modifications, bidders were able to choose language for either version; however, the list of acceptable modifications was getting quite extensive. In essence

what NERA did was to take a close look at the acceptable modifications and from these created two versions. This change gave greater flexibility to bidders in that they could choose between two acceptable standard guidelines for these types of documents. To further standardize these documents across utilities, we suggest that Ameren consider implementing these two standard forms of the post-bid letter of credit.

B. Design Considerations for Next Year's Requirement for Distributed Renewable Energy Generation

In 2011, the Illinois Power Agency Act was amended to add distributed generation renewable energy RECs ("DG RECs") as a target for utilities to procure.[12] The distributed generation targets begin at 0.5% of renewable energy resources by June 1, 2013 and increase to 1% by June 1, 2015 and thereafter. Procurement is to be through multi-year contracts of no less than 5 years. Workshops were held in February and April 2012 to discuss the manner in which DG RECs should be procured. These workshops were well attended by industry participants and addressed technical aspects of how distributed generation procurements may work. However, there is still much that needs to be defined about how a DG REC RFP might work. We list below some of the areas that need to be addressed during the planning process for next year's RFPs.

Priority of DG vs. Wind and Solar RECs: The Act does not explicitly set relative priorities among the technology preference. For example, if all technology targets remain unfilled and only one additional REC can be purchased under the budget, it is unclear which REC should be purchased. However, we believe the Act implicitly gives DG RECs a higher priority than RECs from wind or solar. We come to this interpretation because the Act suggests that wind and solar RECs are to be purchased only "as available," but there is no such restriction on the total DG target.[13]

Bidder qualification: The Act requires that a minimum of 1 MW be bid into a DG REC RFP and envisions a role for aggregators to sign up enough sources to reach this 1 MW minimum. Signing up these resources could be a lengthy and costly process. Therefore, we expect that aggregators will only start doing so once they have been selected as a winner under the DG REC RFP. Given this, bidder qualification should be flexible enough to allow bidders to qualify to bid under the DG REC RFP without having to demonstrate that they have already

[12] The amendment was in Public Act 097-0616, which became effective on October 26, 2011. To the extent available, half of the distributed generation renewable energy resources are to come from devices smaller than 25 kilowatts in nameplate capacity. This goal was also added to renewable energy resources procured via the Illinois Power Agency Renewable Energy Resources Fund.

[13] Only the half of DG to come from devices of less than 25 kW of nameplate capacity is "to the extent available"

signed up the necessary customers to meet the minimum 1 MW requirement. To ensure that winning bidders follow through on their commitments, some level of penalty for non-performance by winning bidders is appropriate. However, a consideration in creating penalties for non-performance is that DG aggregators may be new, small companies without significant financial resources.

Length of Contract: The Act requires that, at a minimum, these be contracts for 5 years. Does a contract for five years provide enough incentives for new distributed generation installations, or should the term be longer? For example, would payment for DG RECs for five years provide the right level of incentive for new solar rooftop installations, which could last 15 to 20 years?

Measuring DG generation: Should generation from DG resources be required to be regularly measured, perhaps with a particular type of meter, or could output be judged through formulas and initial engineering estimates?

Solicit DG RECs in the same RFP as one-year RECs or in a stand-alone RFP: The DG REC legislation is highly prescriptive, including requirements to use aggregators and a minimum contract length of five-years, as discussed above. These requirements raise the question of whether all REC bids can be evaluated in a single REC RFP, or whether it would be preferable to evaluate DG REC bids in a stand-alone RFP. From an implementation point of view, we see benefits in holding a single REC RFP. However, there are a number of issues that need to be resolved before a determination can be made as to whether a single RFP or separate RFPs would be preferable.

With a stand-alone DG REC RFP, at least two important questions would need to be answered. The first is how to allocate the single renewable resources budget between the DG REC RFP and the RFP for other RECs. The Act does not provide guidance on this. A second question is if the DG REC RFP would be held before or after the RFP for other RECs. The order in which separate RFPs are conducted may influence the budget that is available to be spent on DG RECs versus other RECs. This, in turn, could determine the effective hierarchy of priorities of DG, wind, and solar RECs.

A single REC RFP would require that multi-year DG RECs be evaluated against one-year REC bids. A joint evaluation of DG and other RECs would not raise the concerns raised above about how to split the renewable resources budget. Holding a single RFP may also be important if the Act is read as setting a strict priority order between DG, wind, solar, and locational REC priorities.