ENVIRONMENTAL LAW & POLICY CENTER
Protecting the Midwest's Environment and Natural Heritage

Comments Concerning the Illinois Power Agency's 2013 Procurement Plan
September 14, 2012

The Environmental Law & Policy Center (ELPC), Illinois Environmental Council, Interstate Renewable Energy Council, Respiratory Health Association, Sierra Club Illinois Chapter, and Union of Concerned Scientists (collectively, "Joint Commenters") respectfully submit the following comments regarding the Illinois Power Agency's 2013 Draft Procurement Plan. These comments relate exclusively to the IPA's Renewable Resource Availability and Procurement Analysis in Section 8 of the Draft Plan. The Joint Commenters also note our support for the comments of the Natural Resources Defense Council regarding procurement of incremental energy efficiency under Section 7.1 of the Draft Plan.

I. Introduction

At first glance, the Illinois Power Agency's 2013 procurement plan ("Plan") looks like bad news for supporters of renewable energy in Illinois. Due to "dramatic reductions" in the forecasted load of ComEd and Ameren (due largely to expanded municipal aggregation and other forms of retail competition), the IPA concludes that there should be no new renewable resource procurements for any of the next five planning years. (Plan at 80) A closer look, however, reveals that the IPA has opportunities to procure renewable energy in different ways, despite the load attrition from ComEd and Ameren.

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First, this year's Plan includes, for the first time, a specific distributed generation (DG) procurement program that can be deployed quickly to procure smaller scale renewable resources to meet the Illinois DG and solar "ramp-up" requirements. The Joint Commenters support this DG program and believe it is prudent for the IPA to include it for public review and comment in this 2013 procurement plan. In general, the program is well-designed and reflects best practices from other jurisdictions. However, the IPA should clarify the aggregation requirement and carefully review the proposed price scalar for the proposed standard offer program to ensure DG resources will be procured cost-effectively.

Secondly, there are unexplored opportunities in this Plan to use the alternative compliance payments (ACP) by alternative retail suppliers to procure new renewable energy resources in 2013. As retail customers switch from ComEd and Ameren to alternative retail energy suppliers like Integrys and FirstEnergy, the ACP funds paid by the alternative suppliers into the IPA's renewable energy resource fund (RERF) will grow accordingly. The IPA should be more transparent about how it intends to use these ACP funds to procure renewable energy in 2013. The Plan does propose to use some of the RERF dollars to cover the costs of existing long-term contracts that are now "stranded" because of customer load shifts to ARES. (Plan at 81-82) This proposal is reasonable. However, the IPA should amend its 2013 Plan to allocate the remaining RERF funds for a DG procurement beginning immediately in 2013. In future years, the IPA should discuss the use of the utility and ARES funds *together* in one plan in order to promote transparency and allow a more comprehensive public vetting of the IPA's overall approach to meet the state's RPS goals.

II. The IPA's Decision to Propose a Distributed Generation Program in the 2013 Plan is Prudent.

The Illinois RPS requires that by June 1, 2013 at least 8% of each utility's total supply should be generated from renewable energy resources. To the extent there is room under the statutory rate cap, at least 75% of these resources shall come from wind, 1.5% from solar photovoltaics, and 0.5% from distributed generation (DG). This "DG carve-out" ramps up over the next three years to require 0.75% by June 1, 2014 and 1% by June 1, 2015 and thereafter.

The IPA held workshops in the spring of 2012 to develop a new procurement method to meet the DG carve-out requirements. ELPC and many other stakeholders participated in these workshops. One of the key takeaways from the workshop process was that there are important differences between utility-scale and DG projects and indeed even between small and large DG projects that require different procurement strategies. For example, small DG projects cannot participate effectively in a traditional auction-based procurement. Accordingly, the IPA has proposed a new DG program in the 2013 Procurement Plan that includes two different procurement strategies tailored specifically for small (<25 kW) and larger (25 kW to 2 MW) DG projects. The larger DG projects will be paid as bid through a competitive procurement. (Plan at 86). In contrast, systems under 25 kW will be "price takers," and will be offered a REC price based on the results of the larger DG auction. The auction prices will be adjusted by a "scalar" to account for cost and other differences between small and large DG projects. *Id.*

The Joint Commenters support this bifurcated program design. It appropriately responds to concerns raised in the workshop discussions and is consistent with current best practices in DG procurement. For example, it is similar to Connecticut's new "Zero-

Emissions Renewable Energy Credit (ZREC) program.[1] The Connecticut ZREC program, like the proposed Illinois DG program, uses a competitive auction for larger DG projects to set a standard offer price for small project RECs. The Connecticut program is generally well regarded in the renewable energy industry and has attracted broad participation from market participants this year.

There are two areas of the DG program that require clarification. Under the "Standard Offer Process" at page 87 of the Plan, the IPA states that the standard offer price "will only be offered to aggregated groups of at least 1 MW." This requirement is vague and could impair market development. The IPA should clarify that project developers will not be required to aggregate 1 MW blocks of individual DG projects before applying to the standard offer program. This type of aggregation would create additional administrative burdens (and therefore costs) by requiring project developers to gather up 100 or more new residential or small commercial customers before they would be eligible to apply for the standard offer.

The IPA should amend the Plan to clarify that it will consider retaining an independent third-party organization to administer the standard offer program. This would satisfy the IPA's statutory requirement to solicit the use of third-party organizations or aggregators to "administer contracts with individual distributed renewable energy generation device owners" and would eliminate the "chicken-or-the-egg" challenge facing project developers that would otherwise be required to sell projects to potentially dozens or hundreds of individual customers *before* knowing whether or not they would be eligible for the DG standard offer program. *See* 20 ILCS 3855/1-75(c)(1). The California Center for Sustainable Energy (CCSE) is an example of such an

[1] *See* http://energy.aol.com/2012/04/30/connecticut-focuses-on-unique-reverse-auctions-to-drive-green/.

independent nonprofit organization. CCSE administers the California Solar Initiative on behalf of San Diego Gas & Electric Co., which includes production based incentive program that is similar to the IPA's proposed standard offer program.[2]

The IPA should also carefully review the process for translating the competitive procurement prices to the standard offer program and should be willing to make adjustments to this scalar going forward. The "scalar analyses" prepared by NERA and Levitan both recommended a scalar factor of 1.25. However, NERA noted that the scalar was "selected to err, if at all, on the high side" and that it may need to be adjusted downward in future plans. (Appendix V-2) We agree. It is not clear, for example, if the NERA and Levitan analysis accounted for the differences in net metering eligibility between the small and larger DG projects. This would affect the size of the scalar necessary to stimulate the DG market. We suggest that in future plans, the IPA consider an automatic price adjustment mechanism that would be transparent and allow automatic fine-tuning of the scalar to adjust to market conditions. For example, the solar program offered by Consumers Energy (Michigan) includes an automatic price adjustment mechanism that reduces the standard offer price based on customer response in each allocation window.[3]

III. The IPA Should Use ACP Funds to Conduct a DG Procurement in 2013.

The Plan's Executive Summary labels 2013 a "Transition Year" for the IPA. The Plan reveals deep and fundamental shifts in the factors underpinning the IPA's current renewable resource planning process. As more and more customers leave Ameren and ComEd for alternative suppliers, the IPA's procurement plan (and the Commission's

[2] See http://energycenter.org/index.php/incentive-programs/california-solar-initiative.
[3] See http://www.consumersenergy.com/content.aspx?id=4841

oversight responsibility) loses more and more relevance. Intervention by the Illinois General Assembly to unite the utility and ARES sides of the IPA's budget would help address the uncertainty and budget fluctuations that have undermined the IPA's confidence in procuring new renewable energy resources. While legislative changes are outside the scope of this IPA planning process, the IPA should support efforts in Springfield to resolve the fundamental load stability issues that impair the IPA's ability to effectively plan for the future.

In the meantime, there are important steps that the IPA can take *in this Plan* to mitigate some of the effects of retail load shifting and set Illinois on a path towards compliance with its renewable energy goals. For example, the IPA proposes to spend part of the RERF to supplement shortfalls in the utility RPS budgets caused in part by customer load shifts to ARES. (Plan at 81-82) This proposal is reasonable. However, the Plan does not discuss how to use the millions of additional dollars that remain in the RERF other than to recommend that the funds "be allowed to roll-over for use in subsequent years." (Plan at 82) Although difficult to project with complete confidence, it appears that there may be more than sufficient funds to support a DG procurement in 2013 *even if* the IPA uses part of the RERF to supplement the 2010 long-term contracts.

Our understanding, based on publicly available information, is that there is approximately $15 million in the RERF as of September 1, 2012. ($12.8 million pre-existing funds plus approximately $2 million paid in on the first of September.) Next year, we expect the ARES to deposit approximately $40 million based on the ICC's most recent estimate of ACP rates.[4] The current budget shortfall for ComEd's 2010 long-term contracts is just over $3 million for 2013-14, climbing to approximately $5 million

[4] http://www.icc.illinois.gov/downloads/public/ACP%20Rate%20History%20as%20of%202012-07-02.pdf

annually for delivery years 2014-15 and 2015-16. (Plan at 80). Ameren has a shortfall beginning in delivery year 2016-17. (Plan at 77) This means that the IPA should have over $50 million in the RERF as of September 1, 2013 *even if* it chooses to use some of the funds to supplement the 2010 long-term contracts.

In subsequent years, the ACP rates for the ARES will likely max out due to the combined effect of the 2010 legacy long-term contracts and a correspondingly smaller utility retail load.[5] This higher rate will also apply to a much larger volume of ARES load as customers continue to switch from utility supply service. Although it is not entirely certain whether the ARES load will remain stable at over 100 million MWH, it is at least reasonable to expect total ACP payments to exceed $100 million annually in future years. The following table illustrates future ACP payments assuming that current load shifting trends continue and that ARES load stays relatively stable over a five-year planning horizon.

Year	**ARES Load (MWh)**	**ACP**	**Total Payments (million $)**	**Date Paid**
2011-2012	**78,000,000**	**$0.058**	**$2.26**	**9/1/12**
2012-2013	**97,500,000**	**$0.826**	**$40.3**	**9/1/13**
2013-2014	**112,000,000**	**$1.49**	**$83.4**	**9/1/14**
2014-2015	**114,000,000**	**$1.89**	**$107.7**	**9/1/15**
2015-2016	**115,000,000**	**$1.89**	**$108.7**	**9/1/16**

[5] ACP rates are calculated as "equal to the total amount of dollars that the utility contracted to spend on all renewable resources for the compliance period divided by the forecasted load of eligible retail customers, at the customers' meters, as previously established in the Commission-approved procurement plan for that compliance year." 220 ILCS 5/16-115D(d). This amount may not exceed a "maximum" rate calculated based on the statutory rate cap for utility customers in Section 1-75(c) of the IPA Act, which is projected to be approximately $1.89/MWH of sales.

This illustrates that even using conservative estimates, the IPA should have plenty of money to supplement the 2010 long-term contracts *and* move forward with a DG procurement in 2013. The IPA notes that it has been granted a legislative appropriation to spend \$8 million in the 2013 fiscal year. (Plan at 82) The Agency would only need to spend \$1.4 million of this to supplement the 2010 long-term contracts (\$3,196,181 shortfall less approximately \$1,784,000 in ACP payments from ComEd hourly-priced service customers). Assuming that the IPA allocated the remaining \$6.6 million of its appropriation for a DG procurement in 2013, the RERF would still contain approximately \$7 million to roll forward to future years.

We understand that the State has borrowed a portion of the RERF in the past. However, the IPA's concern that RERF funds may be borrowed again in the future must be balanced against the IPA's statutory duty to procure new renewable energy resources and the reality that the ARES' ACP payments will likely grow significantly in future years. Even if the IPA enjoys flexibility regarding *how* it spends the RERF, it does not appear to have discretion regarding *whether* to spend it. The IPA Act is clear that the agency shall use the RERF to "procure renewable energy resources at least once per year." 20 ILCS 3855/1-56(c). To the extent available, these resources must meet the same wind, solar, and DG carve-out goals that apply to the procurement for electric utilities. 20 ILCS 3855/1-56(b).

We also understand that the IPA believes that it does require Commission approval to spend the ACP funds in the RERF in any fashion, "either within or outside of a Commission-approved procurement plan." (Plan at 81) However, it is very important for the IPA's procurement plans to be as transparent as possible about overall program budgets and capacity targets.[6] Transparency will help the industry identify market opportunities in Illinois and foster more informed public dialogue to improve the IPA's strategies and plans. Therefore, even if the IPA Act does not technically require it, the IPA should endeavor to develop a renewable energy procurement plan that is as comprehensive as possible and that includes a rough total budget and targeted capacity using all resources available to the IPA. If the Commission determines that it only has jurisdiction over the utility spending, then it can simply review only that portion of the plan. But in any event the public should be given the opportunity to engage with the IPA on a more meaningful and complete plan to meet the overall Illinois RPS goals.

IV. Conclusion

The IPA should amend its 2013 Procurement Plan to procure the amount of DG RECs required by statute, up to the $8 million appropriated by the legislature less the amount used by the IPA to cover stranded costs from the 2010 long-term procurement. The IPA should also clarify the aggregation and cost scalar requirements for the proposed DG procurement program in order to ensure a cost effective procurement. In future years, the IPA should discuss the use of the utility and ARES funds *together* in one Plan in order to promote transparency and allow a more comprehensive public vetting of the IPA's overall approach to meet the state's RPS goals.

[6] For example, the Solar Energy Industry Association emphasized in prior comments that a "transparent market roadmap" should be the overarching goal of the IPA's planning process. See https://www2.illinois.gov/ipa/Documents/SEIA_VS_Illinois2012-0330-2-2.pdf

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