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Illinois Power Agency
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Re: Electricity and Capacity Procurement for Eligible Retail Customers Request for Stakeholder Comments

CleanChoice Energy, Inc. ("CleanChoice") respectfully submits the comments below to the Illinois Power Agency ("IPA")'s Stakeholder Comment opportunity regarding Electricity and Capacity Procurement for Eligible Retail Customers.

CleanChoice is a licensed Alternative Retail Energy Supplier ("ARES") and has been providing 100% wind and solar products to Illinois customers since 2013. Further, CleanChoice Energy is a mission-driven renewable energy company based in Washington, D.C., with more than 130 employees. We envision a world free of catastrophic climate change with pure, clean air and abundant renewable energy. We work to switch as many American homes and businesses to clean, renewable energy as possible and proudly serve hundreds of thousands of customers across the United States.

CleanChoice appreciates the opportunity to provide feedback on this matter. Should you have any questions, please contact Rachel Smucker at rachel.smucker@cleanchoiceenergy.com.

Respectfully,

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CleanChoice Energy's Comments Re: Electricity and Capacity Procurement for Eligible Retail Customers Request for Stakeholder Comments

Introduction

Currently electricity markets are significantly dislocated. The disruptions from the pandemic, the war in Ukraine, inflation and economic concerns have all made electricity producers nervous not to over-promise and under-deliver. This is reflected in extremely costly forward market prices which have started to moderate but are still very high. Natural gas prices at the Henry Hub–the most liquid trading point in North America–have varied greatly over the past few months and occasionally reached record highs over $9/MMBTU.[1] Further, at different points the Henry Hub price has closely tracked movements in the European natural gas benchmark suggesting that North American natural gas prices are beginning to tether to global indexes–which are much higher–as exports continue to boom. As you know, natural gas is the commodity historically used to set the clearing price for electricity. However, the electricity markets have been even more volatile and expensive than suggested by the high gas prices. As part of CleanChoice's internal price discovery work for procuring electricity we've seen ComEd July 2022 Peak prices go as high as $250/MWh in the forward market. These prices do not reflect the higher natural gas prices. Even if gas prices stayed elevated at $8-9/MMBTU, wholesale electricity prices should still be under $100/MWh. Historically, in similar circumstances, market dynamics like this were driven by fear and uncertainty and not commodity price fundamentals.

While the IPA must chart a path through the current market, CleanChoice observes that the biggest risk to long-term affordability would be to fail to execute on Illinois' long-term energy transition goals. A slow transition will be expensive, volatile and risky. More power generation with zero fuel costs will greatly benefit Illinois consumers.

In that regard, perhaps the most important policy the state must figure out is how to rapidly interconnect new solar and wind farms to the electric grid. Interconnection costs and delays remain a critical barrier to overcome. The IPA should coordinate closely with the Illinois Commerce Commission ("ICC") to accelerate interconnection of renewable energy facilities, including:

- Increasing transparency of targeted grid information by establishing open and transparent interconnection queues, fees, and equipment costs;
- Adopting alternative solutions to Direct Transfer Trip (DTT);
- Adopting technical standards;
- Allowing interconnecting customers to self-build system upgrades;
- Standardizing interconnection application processes; and

[1] *Natural Gas Weekly Update*. U.S. Energy Information Association, July 2022. https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/07_07.
See also: *Natural gas surges above $9, hits the highest since 2008 as inventories stay low*. CNBC, May 25, 2022. https://www.cnbc.com/2022/05/25/natural-gas-surges-above-9-to-highest-since-2008-on-low-inventories.html

- Formally incorporating energy storage-related provisions into interconnection rules.[2]

In addition, Illinois should take steps to effectively allocate interconnection costs by adopting a cost sharing policy that distributes the costs across a more appropriate range of beneficiaries, properly recognizing that when constructing bulk power system upgrades of a certain magnitude, substantial benefits from constructing those upgrades may flow to customers other than to the DERs seeking to interconnect.[3] A set of payments to overcome interconnection costs or a policy allowing the state utilities to include interconnection costs in rate base would greatly accelerate the buildout of new zero-fuel-cost power generation.

While some states have adopted a cost-sharing mechanism for interconnection, CleanChoice believes states committed to the energy transition should go further and socialize all interconnection costs. This would mean that every project that could obtain permits would be eligible to interconnect. This one change would eliminate one of the largest barriers to growth in renewable energy.

CleanChoice recognizes that a new Interconnection Working Group has been established as a result of the Climate and Equitable Jobs Act of 2021, which is charged with addressing these and other topics related to interconnection. We applaud this continued effort to bring together a diverse set of stakeholders to advance a more innovative and efficient interconnection process in Illinois. CleanChoice recommends that this work is not done in isolation and is instead done in conjunction with reforms to distribution system planning procedures and the implementation of grid modernization measures to achieve the best results.[4] Understanding that some of these policies may not be in the purview of the IPA or even the ICC and may require legislation; it's important to recognize interconnection as an important area of focus to accelerate access to low-cost energy.

Questions

1. What additional products beyond the block energy products that are currently procured should the IPA consider for inclusion in the procurement plans that would help mitigate the impacts of high and volatile electricity prices on eligible retail customers which would meet the product definitions set by statutory requirements and the ICC?

Block energy products are the best product to manage commodity price risk. The IPA should consider blending tenures of these blocks over several months–trading weekly–to avoid exposure to any one market environment. There is as much risk of going too long now as being too short.

The IPA should also consider Distributed Energy Resources ("DERs") as a hedging tool. If deployed thoughtfully and integrated into the electric grid in a way that optimizes their usage, DERs have

[2] *Integrating Distributed Solar and Storage: The Keystones of a Modern Grid.* Coalition for Community Solar Access, February 2022. See page 5. https://www.communitysolaraccess.org/wp-content/uploads/2022/02/CCSA_BRO-White-Paper_20220214.pdf

[3] *Id. at page 4.*

[4] *Id.*

enormous potential to provide significant benefits to all consumers in the form of reduced costs and emissions as well as improved reliability, resiliency, power quality, and efficiency.[5]

2. Should the IPA establish a market analysis process outside of the annual electricity procurement plan that would formally review market conditions in order to identify potential challenges that changing market conditions could pose to the procurement process?

Yes. Importantly, if it doesn't already, the IPA should examine whether there are sufficient suppliers providing pricing to ensure the IPA such that procurements are competitive.

3. How will current market conditions impact the near- and longer-term eligible retail customer switching patterns?

This is difficult to forecast. ARESs procure from the forward market, whereas the default rates are usually set from historic electricity purchases. In a market with rising forward prices, ARES may not be as competitive against the historical default prices. However, as prices deflate again this trend could reverse and markets will be in a period where the default rates are not as competitive compared to the ARES. This assumes that both ARES and the IPA are passing through market costs rather than some uncompetitive amortization of costs.

In this changing market environment, the purely economic buyer would be a price-seeker and migrate towards the lower price at different times. However, these migrations are not fast and can take many months or years to happen. Further, many shopping retail energy customers are not shopping on price– instead they're looking for a different mixture of renewable energy or enrolling for a bundle with smart home tech or other services. In general, in markets with elevated prices it is not advisable to take on too many long (multi-year) contracts to avoid being stuck at an elevated price for an extended period of time.

4. Given the mix of competitive wholesale markets and traditional regulated markets in MISO that creates disconnects with the Illinois market structure, would having Ameren Illinois and the Illinois portions of MidAmerican either join PJM, or join ComEd in the establishment of a single state RTO for Illinois be beneficial to serving eligible retail customers, provide benefits to the competitive market, and/or provide better options for resource adequacy? While the IPA cannot make such a change through its procurement plans, consideration of these options could help inform future policy decisions for the State.

A single-state RTO would be inefficient. The cost of operating an RTO is high and the benefits are best met through diversification. Illinois should seek to take advantage of surplus generation in adjacent states and markets when it needs additional generation. One important advantage of being part of a

[5] *Id. at page 73.*

larger RTO is that you potentially have more wholesale suppliers bidding into procurements as they will be able to manage their own risks and credit positions across many states. Illinois should avoid monopoly, oligopoly and monopsony risks in order to see the best results over time.

In addition, CleanChoice recommends that Ameren and MidAmerican join PJM, which has the most reliable and transparent market structures.

5. What changes should the IPA consider making to the energy hedging strategy that would be consistent with the Illinois Power Agency Act, Public Utilities Act, and relevant orders issued by the ICC which would improve the ability to deal with extremely volatile energy prices?

In general, the best way to take volatility out of prices is to hedge over a longer period of time in order to amortize higher prices over lower-priced months as well. This is because electricity prices are very seasonal – increasing and decreasing between peak and shoulder months. This does create the risk of being "stuck" at a higher price for a longer period of time; however, the costs the IPA faces are real and can only be managed and not avoided. At this time, CleanChoice does not have any specific recommendations regarding alternative energy hedging strategies that are compliant with applicable Illinois laws and Commission Orders.

6. Should the frequency and timing of energy procurements be modified?

It depends on current market conditions and whether the IPA is satisfied with the pricing you are getting. More frequent trading can reduce exposure to any single market environment and is advisable in some market conditions. This has been especially true over the last few months when forward market prices have swung by $50/MWh or more from week to week. There are also periodic moments of poor liquidity in power markets, and this is where these procurements become more art than science. Energy traders have judgment they develop over time about whether a market is providing fair pricing or not.

7. Should the IPA consider procuring energy in block sizes other than 25 MW or in different sized blocks within the same procurement?

Increasing block sizes would likely shrink the number of bidders and should be avoided. In fact, the IPA should consider smaller blocks and potentially procure from DERs if they can reduce costs at the RTO. Deploying this strategy would help to increase the number of bidders, which leads to more competitive prices.

8. Is it reasonable to consider modifications to the hedging strategy, if the recent high and volatile energy prices may be a short-lived phenomenon?

As we mentioned above, the costs that the procurements face cannot be avoided. They can only be managed. Certainly, managing them over a longer period of time is a strategy that can be used to avoid

large one-time price shocks; however, markets can also go down. A layering in of hedges over a long period of time can reduce exposure to any one market environment.

9. Should the current approach to summer hedging percentage targets and target procurement volumes for the months of June, July and August be changed to increase or decrease these targets and to reduce the volumes procured in the Spring procurement event that is held immediately prior to these delivery months?

CleanChoice does not have feedback on this issue at this time.[6]

11. Do CMCs represent a viable hedging approach over the five-year horizon of the CMC program that can be matched with the energy hedging strategy?

CMCs have an upside and a downside as a hedging strategy. The upside is that ratepayers should be able to benefit from energy markets that are elevated by essentially getting a rebate from the CMC supplier. Ratepayers are already making these procurements and should see economic value in addition to the carbon benefits. The IPA's CMC Procurement Plan[7] notes that if the price-per-megawatt-hour calculation results in a net negative value, the CMC supplier will multiply this value by the applicable CMC contract quantity and pay the net value to the electric utility.

The downside to the CMC as a hedging strategy is that the timelines for when CMC true-up payments to consumers could happen and when the IPA must make risk management decisions and procurements are not aligned and could be dramatically different. The IPA has monthly costs it must manage where the CMC payments are on a different timeline. Because these aren't aligned, in a period of elevated prices the state would effectively be using the balance sheet of individual consumers to borrow money until true-up payments can be made in the future. This would not achieve the stated goal of hedging energy costs.

The process of refunding or trueing up costs to ratepayers over time for any payments made to the utility from the CMC supplier as outlined in ComEd's tariff is complicated.[8]

And because there is a customer protection cap on the CMC charges, any current period upside might be needed in a future period should energy prices decrease significantly. A better approach might be to allow the program to operate for a few years and see what scale of economic upside is banked and then evaluate the size and timing of any rebates to consumers.

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[6] CleanChoice does not have comments in response to Questions 9-10, 12, and 15-19 at this time.

[7] *Carbon Mitigation Credit Procurement Plan.* Illinois Power Agency, September 29, 2021. See page 22. https://www2.illinois.gov/sites/ipa/Documents/RedlineofDrafttoFiledCMCProcurementPlan29SEP2021.pdf

[8] https://www.comed.com/SiteCollectionDocuments/MyAccount/MyBillUsage/CurrentRates/82_RiderCFRA.pdf

13. Will timing differences in the adjustment of the level of payments or credits for CMCs versus the month-to-month changes in the Purchased Electricity Adjustment that are driven in part by the results of the hedging for energy conducted by the IPA, negate any of these benefits?

As we note in our answer to Question 11, timing is very much the risk of using CMCs. There could be ways to use a line of credit or a securitization to smooth out the upside and downside; however, CMCs are still relatively new without a long track record of payments that might be needed for a financing solution.

14. Are there changes to the capacity procurement approach for Ameren Illinois eligible retail customers that could improve the ability to mitigate volatile capacity prices?

One potential option is for Ameren to join PJM to reduce capacity volatility.

20. Given that the ICC, not the IPA represents Illinois in wholesale market matters, how can the IPA better engage in an ongoing dialog with the RTOs (PJM and MISO) and their respective Independent Market Monitors that would provide information regarding the performance of their respective capacity markets and the potential modifications to these markets that are being debated or contemplated?

Many RTOs have established collaborative stakeholder forums and working groups to consider a wide variety of topics that have allowed for better communication across the various participants. If the IPA is not engaged already in PJM and MISO's stakeholder forums and working groups, the IPA should consider joining, in coordination with the ICC.

Conclusion

CleanChoice Energy appreciates the opportunity to comment and looks forward to future discussions on this matter.