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To:

Anthony Star
Director, Illinois Power Agency
160 N LaSalle St.
Chicago, IL 60601

From:

Dylan DeBiasi
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Re: Request for Comments on Long-Term Renewable Resources Procurement Plan

Carbon Solutions Group (CSG) would like to thank the Illinois Power Agency (IPA) for the opportunity to comment on the development of the Long Term Renewable Resources Plan (LTRRP)

CSG is a REC marketer and aggregator. We have been active participants in the Illinois REC market for a number of years. We have also served as a stakeholder and winning bidder/aggregator in the Supplemental Photovoltaic Procurement, Utility Distributed Generation Procurement, and the Utility Scale REC Procurement. We have worked closely with installers, system owners, and other market participants across a wide range of system sizes and geographical areas.

With our comments we respectfully encourage the IPA develop an LTRRP that incentivizes a wide range of businesses and project types and that they reserve the right to tweak and improve the program as issues come to light throughout the early implementation phases.

A. GEOGRAPHIC ELIGIBILITY OF RENEWABLE ENERGY RESOURCES

1. What level of documentation and analysis should be required from an adjacent state project as part of a request that the Agency consider determining that the project is eligible to provide RECs for the Illinois RPS?

See response to question # 2 below.

2. What would be an appropriate methodology for the Agency to use to determine that a project located in a state adjacent to Illinois meets the public interest criteria enumerated in Section 1-75(c)(1)(I)? For example, should it be a weighted scoring system based upon each of the criteria outlined in the law contributing towards meeting a minimum aggregate score, or does a threshold level of compliance with each criterion have to be fully demonstrated?

CSG's answer is organized in the following manner:

- Overview of Understanding of Public Benefit Criteria
- Introduction of CSAPR & Comparison of Objectives with the Act
- CSAPR Methodology (HYSPLIT)
- Illinois Non-Attainment Area Boundaries
- CSAPR & IL EPA Air Transport Model Results
- Facility Registration Process
- PJM GATS & MRETS Tracking System Distinctions
- Proposed Non-Rate Recovery Procedure

Overview of Understanding of Public Benefit Criteria

Our understanding is that there are mainly five criteria which must be satisfied by any adjacent state facility. The first criteria being the minimization of SO_x, NO_x, particulate matter and other pollution adversely affecting the State. The second criteria being enhancing resiliency and reliability of the electricity distribution systems. The third criteria being increasing fuel and resource diversity. The fourth criteria being meeting goals that limit carbon dioxide. The final criteria is the more general requirement that the facility contribute to a cleaner and healthier environment in Illinois.

We posit that the first and fifth requirements are very similar to the EPA's Cross-State Air Pollution Rule (CSAPR). Cross-State Air Pollution Rule (CSAPR), 40 CFR Part 98 The federal Cross-State Air Pollution Rule is an emission allowance trading rule that was intended to result in

reductions in emissions of SO₂ and NO_x from states in the eastern half of the United States (including Illinois) to improve air quality for ozone and fine particulate matter.

The second requirement of enhancing resiliency and reliability can reasonably mean at least two things. Resiliency could suggest a preference for facilities that are located near nodes that currently may be underserved due to unique load profiles or lack of infrastructure or electricity supply. Therefore, situating facilities closer to load (as is accomplished by distributed generation) may contribute to grid resiliency. Reliability likely refers to a preference for baseload generation capacity.

The second and third requirements imply that the facility shares the same distribution grid. We suggest that the facility must prove that it is interconnected or sited within (and thereby displaces load) power from MISO or PJM.

One could argue that not all renewable resources contribute to resiliency and reliability equally. Thus, the concept of renewable baseload generation might be deemed premium to intermittent renewable resources. Furthermore, the larger the facility in many cases the less resilient it might be. Therefore, perhaps the concept of an adder might be applied to more distributed (smaller facilities) and more baseload.

The fourth criteria would be met by any facility meeting the definition of renewable resource in any adjacent state. Therefore, we would support a standard for which the facility proves that it is interconnected to PJM or MISO in a state adjacent to Illinois.

In the following paragraphs we assert that any facility which is interconnected an electricity distribution grid which is common to Illinois and in a state adjacent to Illinois should be viewed as meeting the threshold for public benefit to ratepayers in Illinois. We assert this due to the air transport models evolved by EPA and used by Illinois EPA which show a super regional impact by fossil emitters on Illinois residents. The global impact of carbon dioxide emissions should make all facilities in adjacent states considered impactful and that the limiting factor for facilities within the adjacent states should be the sharing with Illinois of electric distribution grids to ensure that they might have a positive impact on resiliency and reliability.

EPA's CSAPR Program & Comparison With the Act

We believe that leaving the language at adjacent states accomplishes the required results with regard to requirements one and five. This is because from an air quality standpoint (SO_x, NO_x, Ozone, Particulate Matter) the air transport models published in the last few years as part of CSAPR (Cross State Air Pollution Rule) suggest that emissions from all of the adjacent states would impact the Illinois air shed.

The preamble to the Act states:

“The General Assembly finds and declares:

(1) Reducing emissions of carbon dioxide and other air pollutants, such as sulfur oxides, nitrogen oxides, and particulate matter, is critical to improving air quality in Illinois for Illinois residents.

(2) Sulfur oxides, nitrogen oxides, and particulate emissions have significant adverse health effects on persons exposed to them, and carbon dioxide emissions result in climate change trends that could significantly adversely impact Illinois.”

The EPA’s executive summary from CSAPR final rule published in the Federal Register states:

The CAA section 110(a)(2)(D)(i)(I) requires states to prohibit emissions that contribute significantly to nonattainment in, or interfere with maintenance by, any other state with respect to any primary or secondary NAAQS. In this final rule, EPA finds that emissions of SO₂ and NO_x in 27 eastern, midwestern, and southern states contribute significantly to nonattainment or interfere with maintenance in one or more downwind states with respect to one or more of three air quality standards—the annual PM_{2.5} NAAQS promulgated in 1997, the 24-hour PM_{2.5} NAAQS promulgated in 2006, and the ozone NAAQS promulgated in 1997 (EPA uses the term “states” to include the District of Columbia in this preamble). These emissions are transported downwind either as SO₂ and NO_x or, after transformation in the atmosphere, as fine particles or ozone.

We believe that its informative to compare the objectives of the two programs. We assert that it can be shown that EPA modeling supports that fact that all adjacent states (and thus facilities in those states which share distribution grids with Illinois) impact the health and safety of Illinois residents.

CSAPR Methodology (HYSPLIT)

Importantly, for Illinois residents in the development of CAIR and CSAPR the EPA utilized back-trajectory climatology techniques. Intuitively, this model uses NOAA data to ascertain where emissions originated on days when air emissions were worst (most concentrated) in a given geographic area.

CSAPR provides a 4-step process to address interstate transport of certain air pollutants:

1. Identifying downwind receptors that are expected to have problems attaining or maintaining clean air standards (i.e., NAAQS);
2. Determining which upwind states contribute to these identified problems in amounts sufficient to “link” them to the downwind air quality problems;
3. Identifying upwind emissions that significantly contribute to nonattainment or interfere with maintenance of a standard by quantifying appropriate upwind emission reductions and assigning upwind responsibility among linked states; and
4. Reduce the identified upwind emissions via permanent and enforceable requirements (e.g., regional allowance trading programs).

HYSPLIT (HYbrid Single-Particle Lagrangian Integrated Trajectory)

The EPA utilized the HYSPLIT in order to consider back-trajectory climatological modeling. Meteorological data analysis provides additional insight into the transport of emissions. The most simplistic approach is to evaluate wind direction and speed from a fixed location, such as a National Weather Service meteorological data site. However, it is often difficult to assess where the air mass was, even an hour or two before the measurement was taken.

A more sophisticated analysis can be done by use of a back trajectory model. This type of model starts with a user-supplied location and time and tracks the air mass backwards using output from a meteorological model. This method produces a path that the air mass has taken to get to the desired final location and time, for as long of a period as 48 hours prior. Since nonattainment areas are relatively small and air mass residence time over the nonattainment area is short, a back trajectory model is an important tool in determining from where ozone and precursors are being transported.

The below describes the process EPA underwent to model emissions transport. This process was also used by the Illinois EPA as guidance in determining Non-Attainment Areas (NAA's) within the state.

The following excerpt is from page E-2 of ***Air Quality Modeling Technical Support Document for the Final Cross State Air Pollution Rule Update in August 2016:***

- I. Introduction This appendix describes the back trajectory analysis performed for each of the 19 nonattainment and maintenance receptors in the final CSAPR Update. The purpose of this analysis is to qualitatively compare the transport patterns, as indicated by back

trajectories, to the upwind state-to-downwind receptor linkages identified based on detailed photochemical modeling performed as part of the final CSAPR Update. The modeled contributions of emissions from upwind states to ozone at downwind receptors are the result of the modeled transport meteorology and the emissions of precursor pollutants in combination with the chemical transformation and removal processes simulated by the model. In this analysis, we use back trajectories in a qualitative way to examine one of the factors, the transport patterns, on days with measured ozone exceedances. The back trajectories were calculated using meteorological fields determined based on observations that were constructed in a nearly independent manner from the simulated meteorological fields used in the photochemical modeling for this rule. Therefore, the general consistency between the transport patterns indicated by back trajectories and the upwind/downwind linkages corroborate and add confidence to the validity of the linkages for this rule.

II. Methodology For the back trajectory EPA used a technique involving independent meteorological inputs to examine the general plausibility of these linkages. Using the HYSPLIT (HYbrid Single-Particle Lagrangian Integrated Trajectory) model along with observation-based meteorological wind fields, EPA created air flow back trajectories for each of the 19 nonattainment or maintenance-only receptors on days with a measured exceedance in 2011 and on exceedance days in several other recent high ozone years (i.e., 2005, 2007, 2010, and 2012). One focus of this analysis was on trajectories for exceedance days occurring in 2011, since this was the year of meteorology that was used for air quality modeling to support this rule. The trajectories during the four additional years were compared to the transport patterns in 2011 to examine whether common transport patterns are present. The HYSPLIT model developed as a joint effort between NOAA and Australia's Bureau of Meteorology¹ is capable of computing the trajectory (i.e., path) of air parcels through a meteorological wind field. A "back trajectory" calculated by HYSPLIT is essentially the series of locations in the atmosphere that an air parcel occupied prior to arriving at a particular location of interest. Thus, the HYSPLIT model can be used to estimate the history of an air mass prior to arrival over a given air quality monitor at a given time. Air parcels can follow highly complex, convoluted patterns as they move through the atmosphere. Circular pathways are common due to the clockwise air circulation around high-pressure systems and counter-clockwise circulation around low-pressure systems. A simple west-to-east trajectory could also occur for a parcel following the prevailing westerlies. Local meteorological effects due to land- and seabreeze air circulations or terrain-induced flows can also influence air-parcel trajectories. Strong variations in wind speed and direction often occur in the vertical direction due to the diminishing impact of the Earth's surface on air motion with vertical distance from the ground. The Earth's surface impacts both wind speed and direction because the frictional effect of the surface opposes both the pressure-driven movement of air as well as the turning of the air due to large-scale planetary motion. Thus, air masses may come from different directions at different heights. Highly complex air-parcel trajectories are common, because a given air parcel often experiences the combined effects of numerous interacting air flow systems. Pollutants emitted from sources in one area mix

upward during the day and are transported with the wind flow at the surface and aloft. At night, the pollutants remaining aloft from emissions on the previous day can travel long distances due to the presence of phenomena such as the “nocturnal jet”, which is a ribbon of strong winds that forms at night just above the boundary layer under certain meteorological conditions.

The back trajectories are considered to corroborate the upwind state-downwind receptor linkages if the density plots indicate that air parcels cross over some portion of each upwind state that is linked to that receptor, as determined from the final CSAPR Update modeling. Such a connection indicates that the observed wind patterns can transport pollutants from the upwind state to the downwind receptor and potentially impact ozone concentrations on exceedance days at the receptor. Due to vertical and temporal variations in wind speed and direction, not all trajectories from upwind states are expected to have traversed each upwind state at all vertical levels and times.

The Illinois EPA determined the boundaries to be covered by CSAPR in the below 2016 document which highlights the definition of non-attainment, counties adversely impacted by criteria emissions and using back-trajectory climatology the emissions transport pathways which likely carried the pollutants from and through adjacent states to the areas of adverse impact.

The following excerpt is from page 5 of ***Technical Support Document for Recommended Nonattainment Boundaries in Illinois for the 2015 Ozone National Ambient Air Quality Standard September 29, 2016***

On October 26, 2015, the U.S. Environmental Protection Agency (U.S. EPA) revised the ozone National Ambient Air Quality Standard (NAAQS) in response to numerous studies which link the health effects associated with ozone exposure to increases in mortality, as well as cardiovascular and respiratory impairment. The primary ozone standard was strengthened from 0.075 parts per million (ppm), which was set in 2008, to a new level of 0.070 ppm (80 FR665291; October 26, 2015). U.S. EPA also strengthened the secondary ozone standard to provide increased protection against adverse public welfare effects including impacts on vegetation. This standard is identical to the primary standard (0.070 ppm).

Following the promulgation of a new or revised air quality standard, the Clean Air Act (CAA) requires the Governor to recommend initial designations of the attainment status for all areas of the State. Areas can be classified as ***nonattainment*** (does not meet, or contributes to a nearby area that does not meet the NAAQS), ***attainment*** (meets the NAAQS), or ***unclassifiable*** (cannot be classified based on available data).

Based on the most recent three years of ambient monitoring data (2013-2015), only two counties in Illinois are currently violating the 2015 ozone NAAQS – Lake and Madison counties. Based on an analysis of the factors contained in federal guidance, the Illinois EPA is recommending that portions of the Chicago and Metro-East St. Louis metropolitan areas be designated as nonattainment for the 2015 ozone standard

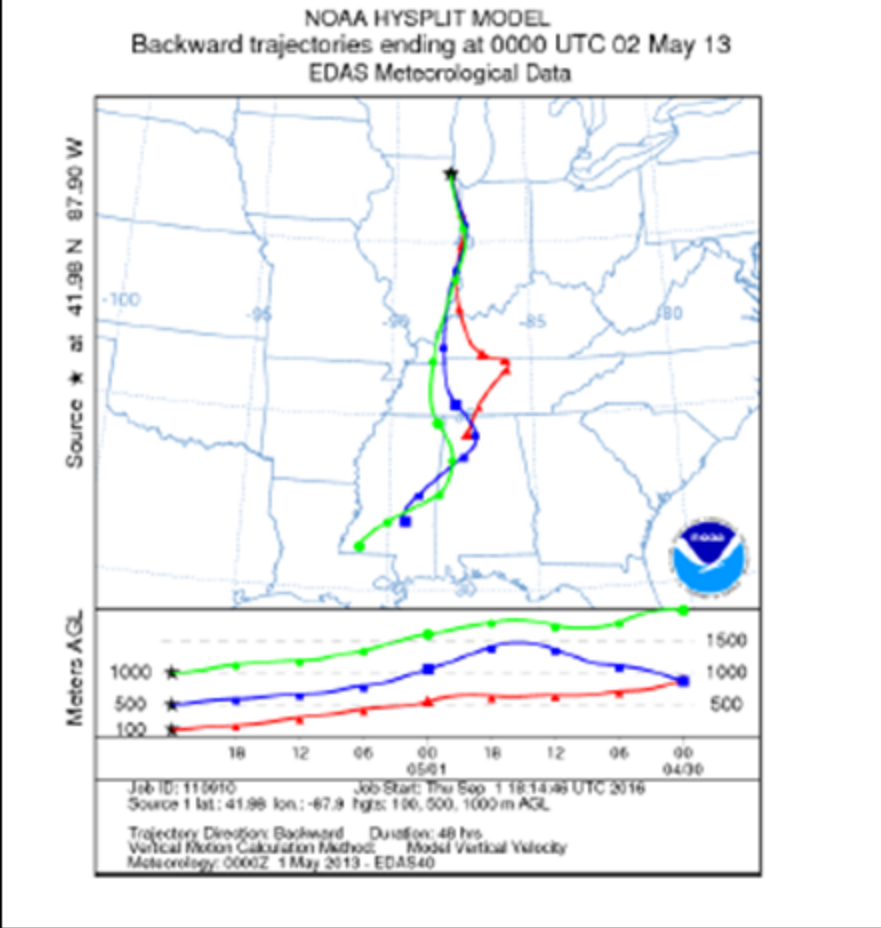
The proposed ozone nonattainment area boundaries are shown in Figure 24 and are included within the boundaries of the Chicago-Naperville, IL-IN-WI Combined Statistical Area (Chicago CSA) and St. Louis-St.Charles-Farmington MO-IL Combined Statistical Area (St. Louis CSA). For the purpose of this analysis, only Illinois counties are assessed. Also, the CSAs in both areas are too large spatially for the outlying counties to contribute in any meaningful way to the violation in each urban area

Table 2. Counties Included in the Chicago MSA and St. Louis MSA

<u>Chicago-Naperville-Elgin, IL-IN-WI MSA</u>	<u>St. Louis, MO-IL MSA</u>
Cook County, IL	Bond County, IL
DeKalb County, IL	Calhoun County, IL
DuPage County, IL	Clinton County, IL
Grundy County, IL	Jersey County, IL
Kane County, IL	Macoupin County, IL
Kendall County, IL	Madison County, IL
Lake County, IL	Monroe County, IL
McHenry County, IL	St. Clair County, IL
Will County, IL	Franklin County, MO
Jasper County, IN	Jefferson County, MO
Lake County, IN	Lincoln County, MO
Newton County, IN	St. Charles County, MO
Porter County, IN	St. Louis City, MO
Kenosha County, WI	St. Louis County, MO
	Warren County, MO
	Warren County, MO

These counties are those with the most significant adverse impact as determined by the Illinois EPA. As we can see these areas of impact are not only affected by adjacent states, but in the cases of WI, IN and MO the adverse effects are felt collectively.

Figure 20. Long distance transport scenario into the Chicago MSA

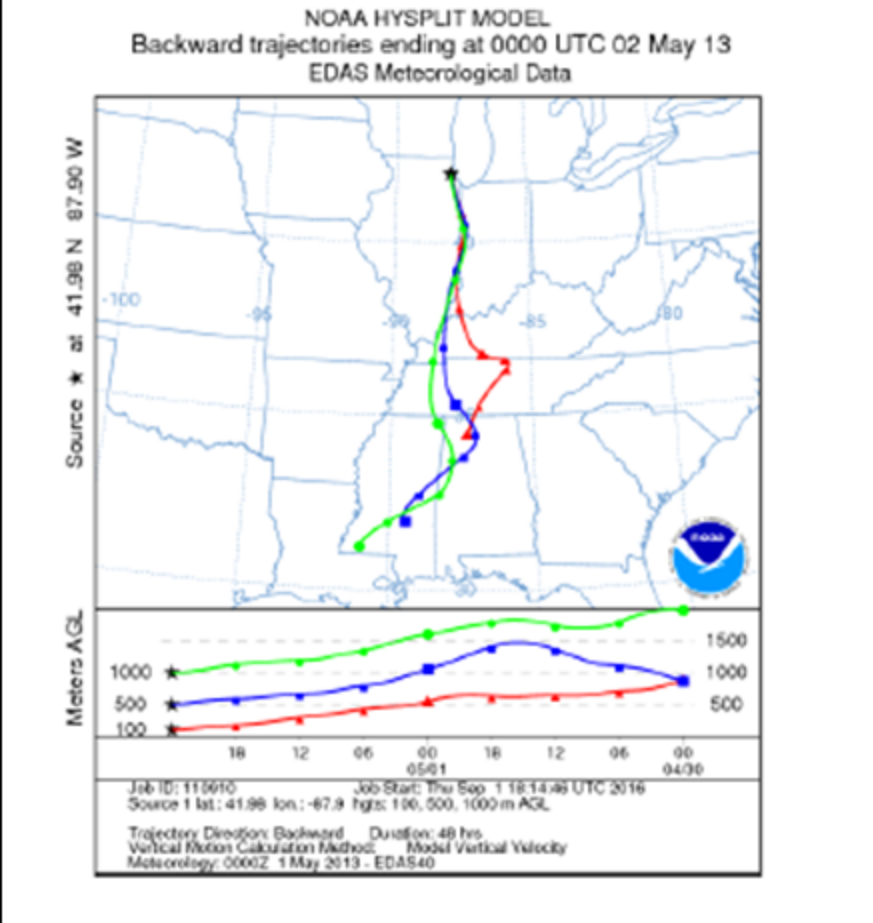


The graphic above shows the backward trajectory and hence the transport of emissions from point sources in locations outside of Illinois. In this instance the graphic shows emissions move through adjacent states Indiana and Kentucky. This transport model clearly shows that emissions in adjacent state can easily (and from probabilistic standpoint often do) become transported into non-attainment zones in Illinois where they adversely impact health, safety and well-being of residents.

Therefore, the displacement or replacement of fossil fuel combusting electricity generation in adjacent states has a very strong likelihood of reduce transportable SOx and NOx emissions; which in turn reduce PM and Ozone transported into Illinois by well understood and evidenced climatological pathways.

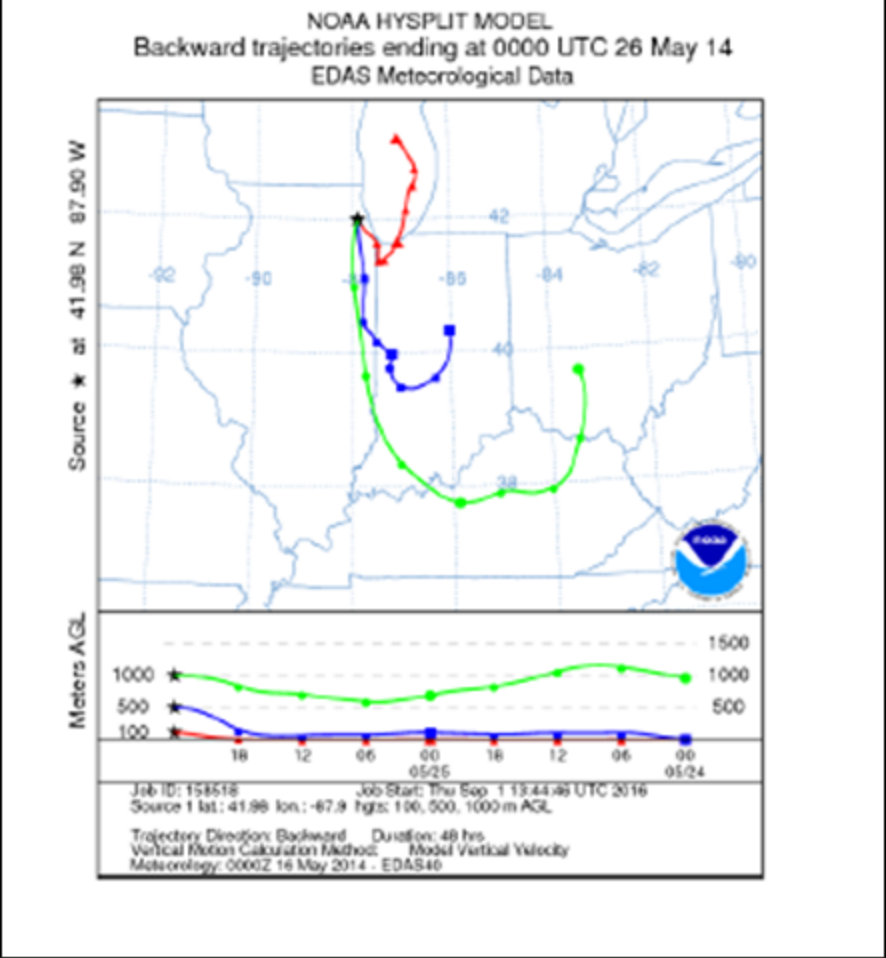
Therefore, we assert facilities located in all Illinois-adjacent states would contribute to the reduction in criteria emissions covered by both the Act and the CSAPR program because the science produced by EPA supports the transport of emissions from all adjacent states into non-attainment areas (as defined by Illinois EPA).

Figure 20. Long distance transport scenario into the Chicago MSA



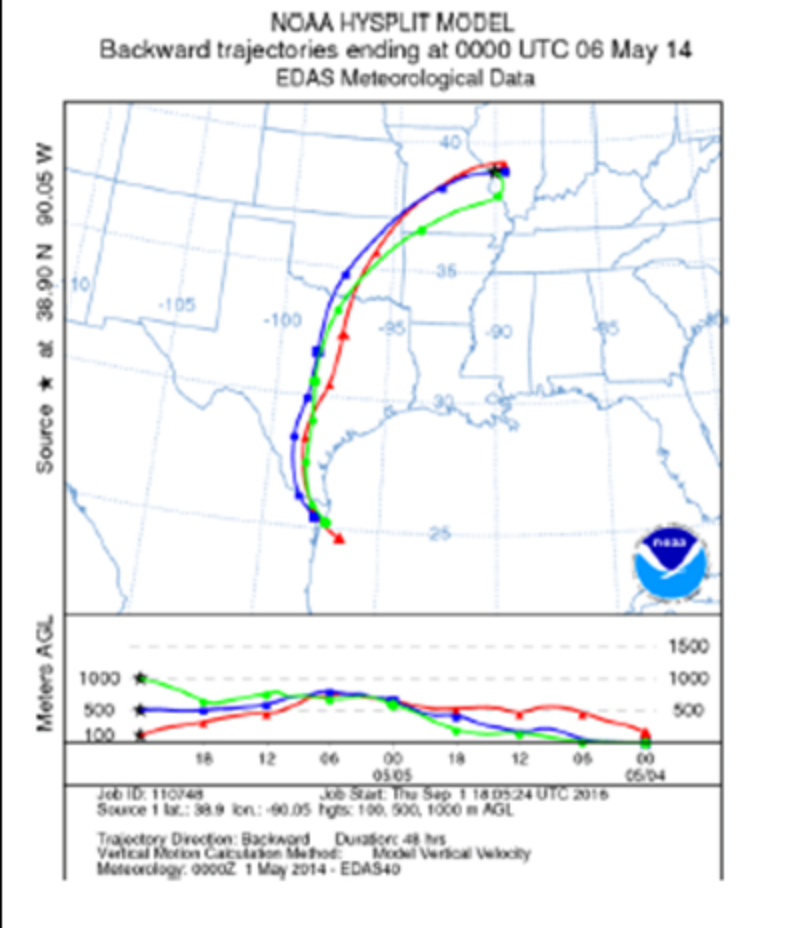
This iteration of the HYSPLIT model shows that emissions flowing through Kentucky and Indiana can impact the Chicago Metro Areas.

Figure 21. Anticyclonic curvature transport scenario into the Chicago MSA

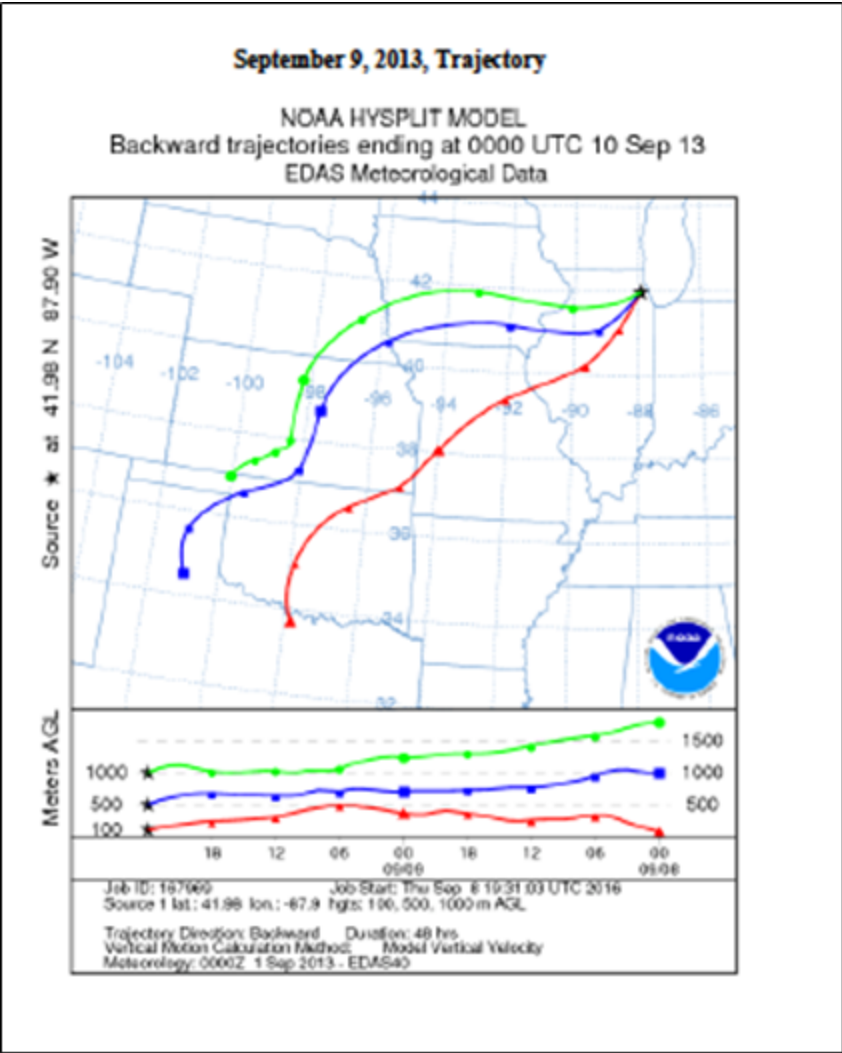


This iteration of the HYSPLIT model shows that emissions flowing through Kentucky and Indiana can impact the Chicago Metro Areas.

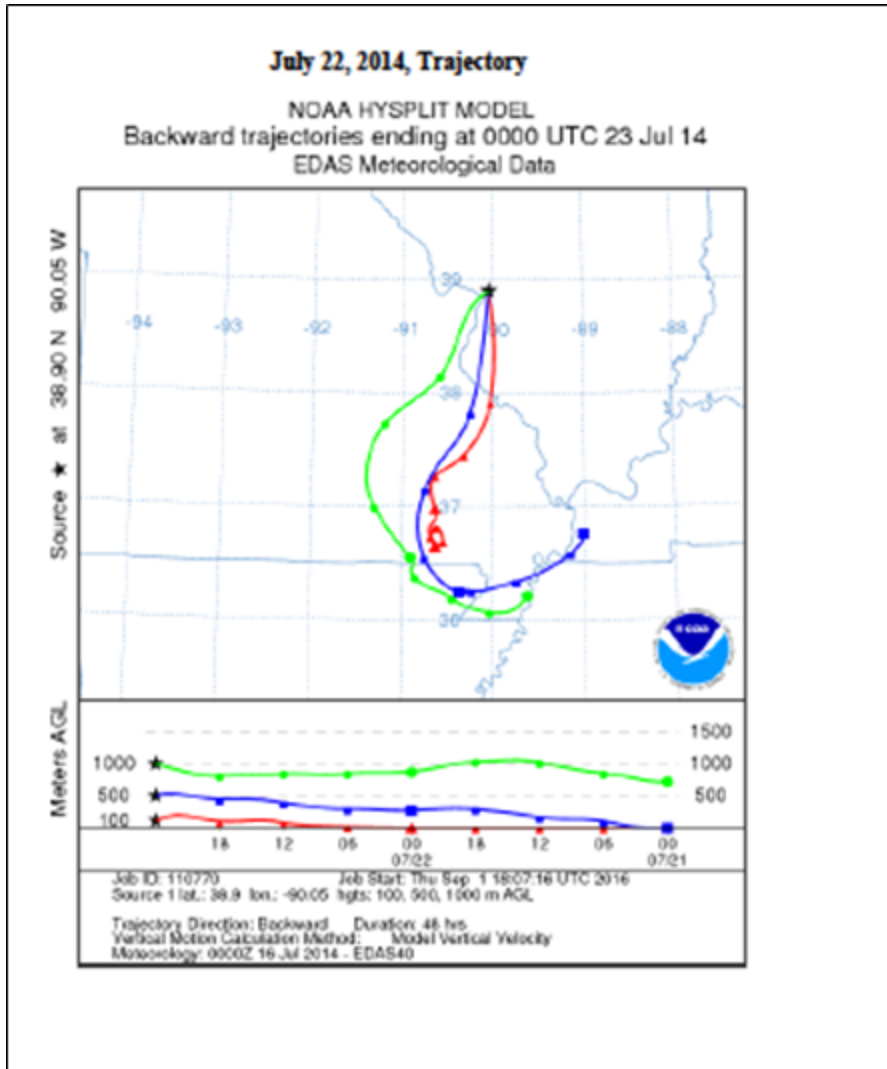
Figure 22. Long distance transport scenario into the Metro-East MSA



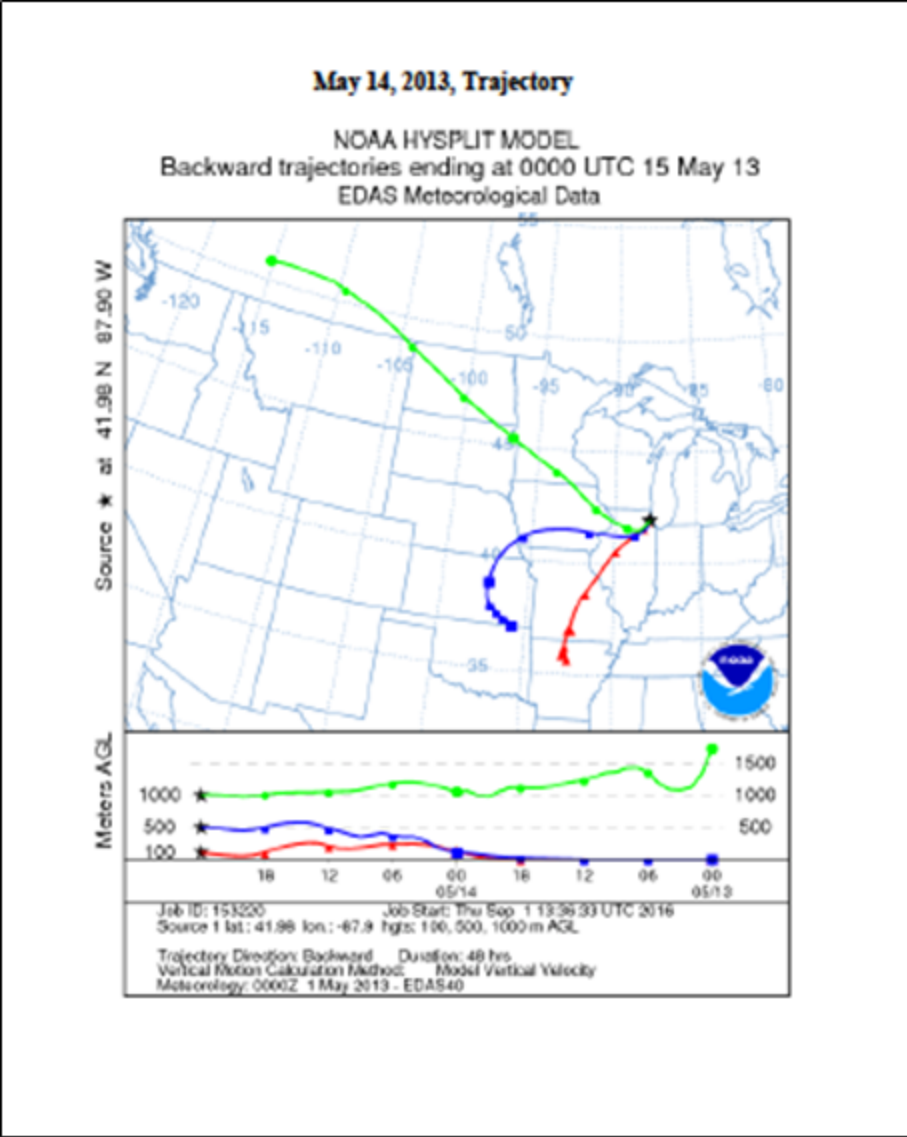
This iteration of the HYSPLIT model shows that emissions flowing through Missouri and as far away as the Gulf Coast can impact the St. Louis Metro Area.



This iteration of the HYSPLIT model shows that emissions flowing through Kentucky and Missouri can impact the Chicago Metro Area.



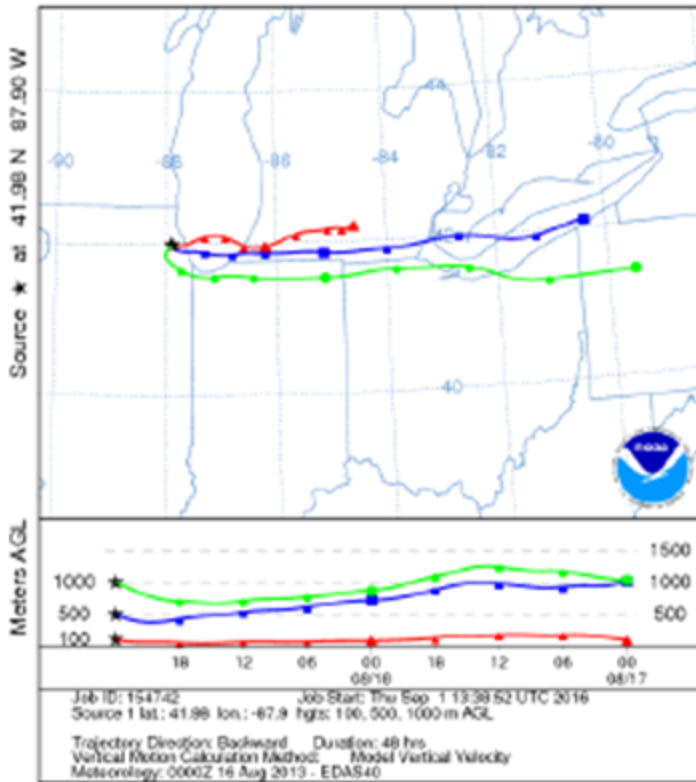
This iteration of the HYSPLIT model shows that emissions flowing through Kentucky and Missouri can impact the St. Louis Metro Area.



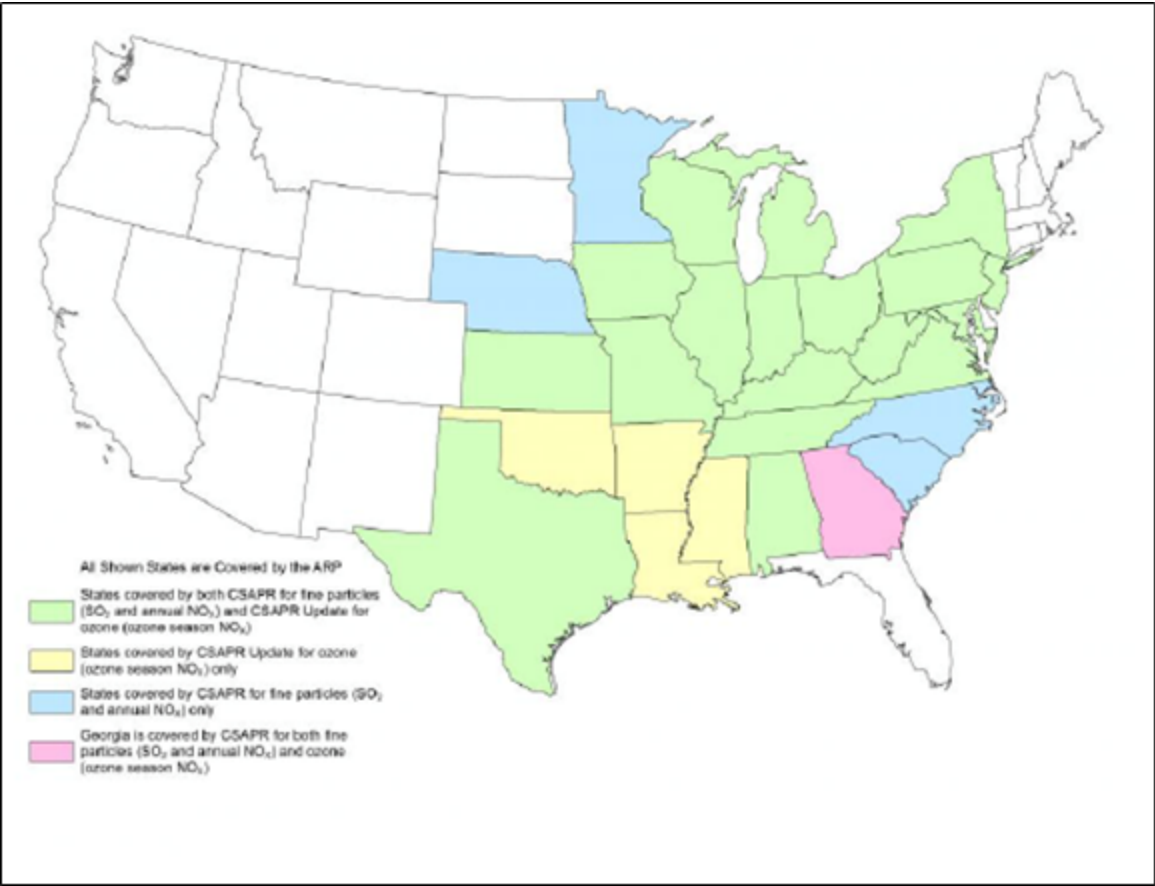
This iteration of the HYSPLIT model shows that emissions flowing through Iowa and Missouri can impact the Chicago Metro Area.

August 18, 2013, Trajectory

NOAA HYSPLIT MODEL
Backward trajectories ending at 0000 UTC 19 Aug 13
EDAS Meteorological Data



This iteration of the HYSPLIT model shows that emissions flowing through Michigan and Indiana can impact the Chicago Metro Area.



<https://www.epa.gov/sites/production/files/styles/large/public/2016-09/transportruleforhomepage.jpg>

In the graphic above the EPA highlights states regulated by various aspects of the CSAPR. Here we can see that Illinois and all adjacent states are covered by both CSAPR for fine particulates (SO₂ and annual NO₂), as well as the CSAPR Update for ozone (ozone season NO_x). Also, its important to note that EPA has delineated the compliance markets for these pollutants into two groups.

Group 1 includes Illinois, Iowa, Indiana, Kentucky, Maryland, Michigan, Missouri, North Carolina, New Jersey, New York, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, Wisconsin and West Virginia.

Group 2 includes Alabama, Georgia, Kansas, Minnesota, Nebraska and South Carolina.

The distinction between the groups was made in large part due to the shared air transport impacts of emission for states within groups. As we can see Illinois and all adjacent states are in the same group (Group 1). This further reinforces the idea that all adjacent states to Illinois (and the facilities within them) can impact health and safety of Illinois residents.

Facility Registration Process

We propose the following steps are to be taken for an adjacent state facility to show that it meets qualification requirements under the five criteria listed in the Act.

1. Records which support interconnection and/or siting in the PJM/MISO in Illinois or an adjacent state.
2. Records which support that the facility does not recover costs via rates regulated by any state (Attached at end of this section – **Proposed Non-Rate Recovery Procedure**)
3. Description of how the project contributes to fuel diversity
4. Description of how the project contributes to resiliency and reliability

In the event that capital was constrained for a particular procurement the following factors could be qualitatively evaluated.

1. Whether the facility is existing (less delivery risk)
2. Whether the facility is baseload (higher capacity utilization receiving a higher score)
3. Whether the facility is distributed (smaller capacity receiving a higher score)
4. Whether the facility delivers other ancillary benefits (such as frequency regulation or demand response)

PJM GATS & MRETS Tracking System Distinctions

We recommend the following guidance as they pertain to tracking systems.

MRETS has two separate boxes for Illinois distinction. One box for "IL ARES" and one for "IL Utility." GATS only has a box for "Renewable" for Illinois purpose (or a blank box).

Alerting MRETS & GATS to both scrub all Illinois distinctions (save <2MW IL sited facilities) is probably a good first step. This will get ahead of the coming challenge of "Public Benefit" as it pertains to "IL Utility" RECs.

The next step might be to allow market participants (or IPA) to provide MRETS & GATS a dynamic list of IL ARES facilities that have proven that they do not recover rates.

Later, once the methodology for proving "Public Benefit" in adjacent states has been established these generators in IA, WI, MI, KY, MO and IN would receive the IL - Utility distinction.

Finally, there is the case of IL sited facilities that do not recover rates which would not need to prove public benefit to receive "IL Utility" distinction. Many of these in fact are DG facilities. They could be given the IL Utility distinction upon approval as an ARES qualifier (i.e. all IL Sited +

ARES qualifying would receive automatic IL Utility qualification) or they could apply later once public benefit has been defined for adjacent states.

As a technical issue although MRETS can currently accommodate an IL ARES and IL Utility distinction; GATS would need to change their distinction from "Renewable" to something that could be bifurcated or dually assigned. For instance GATS would have instead an IL ARES and an IL Utility distinction.

For that matter, MRETS & GATS would both require a distinction for those IL sited, non-rate regulated facilities which qualify for both IL ARES & IL Utility. I'm not sure what to call that; perhaps IL Both or IL ARES + Utility.

Thinking further down the road; a "IL Utility New" distinction might also be appropriate, but that is perhaps not necessary or a ways off.

Proposed Non-Rate Recovery Procedure

We recommend the following procedure be undertaken for a facility to show that it does not recover its costs via rates that are regulated by a State or States.

Examples of determining facility eligibility under 220 ILCS 5/16-115D(a)(3.5)

Example A Subject generating facility: [Mendota Hills LLC](#)

Example B Subject generating facility: [Koda Energy LLC](#)

The Steps set forth below are taken directly from Carbon Solutions Group's Initial Comments filed in ICC Docket No. 16-0267. Notes regarding the practical implementation of the Steps and information gained are provided in italics.

Step 1

Using the REC certificate serial number, the owner of the REC certificate will be able to identify the generation facility through M-RETS or PJM GATS.

For those RECs tracked through M-RETS, if the Facility Ownership Type is listed as "Investor Owned Utility," the inquiry ends and RECs from that generator should not be considered eligible for the Illinois market. In the event that the owner of the REC wishes to contest a finding of ineligibility, it may do so by providing sufficient evidence demonstrating the eligibility of the generator. For those RECs tracked through PJM GATS or for M-RETS tracked RECs with any other Facility Ownership Type, proceed to Step 2.

A Mendota REC certificate will indicate that it is tracked through PJM GATS, which does not identify the facility ownership type. Therefore, the REC owner should proceed to Step 2 to determine generator status.

A Koda REC certificate will indicate that it is tracked through M-RETS, which identifies facility ownership type. In this instance, Koda is identified as “Privately Owned Distributed Generation.” Because it is not listed as “Investor Owned Utility,” the REC owner should proceed to Step 2 to determine generator status.

Step 2

Using the name of the generation facility, review the Federal Energy Regulatory Commission’s (“FERC”) e-Library for either a market-based rate (“MBR”) authorization letter or qualifying facility (“QF”) self-certification filing. The FERC e-Library web address is:

<https://elibrary-backup.ferc.gov/idmws/search/fercadvsearch.asp>.

Generation facilities with MBR authorization or that are self-certified as a QF are generally not “rate regulated” as described in Public Act 99-0906. Owners of RECs who are not the generator and experience difficulty finding either a MBR authorization letter or QF self-certification filing on FERC’s e-Library should consider contacting the generator for assistance in determining the MBR/QF status of the generator.

The goal of reviewing FERC’s e-Library is to ascertain the ultimate ownership of the facility. The MBR and QF documents are the most direct way to do this because they should identify the generator’s parent companies. CSG recognizes, however, that there are various other filings with FERC and documents external to FERC that could be relevant in establishing the ownership of the facility. Upon determining the identity of the generator’s parent companies (which may be the same as the generator), proceed to Step 3.

Because it is not known if Mendota has market-based rate authority or self-certified as a qualifying facility, enter the following basic information as the search parameters in FERC’s e-Library Advanced Search:

Category: check “Submittal” and “Issuance”

***Date:** *if the facility is known to be a wind facility (by its name for example), to help identify a facility MBR authorization, check “Filed date and Issuance Date.” In the Date field input a date that is 5 years before the commercial operation date (found on GATS/M-RETS certificate) and 5 years after in order to limit results.*

Typically, a wind farm will receive its MBR authorization within 6 months of its commercial online date. The commercial online date can always be found on the REC certificate and on the tracking system. Using a broader period (eg: 10 years) will help capture any facilities outside of the norm.

Hydro and other facilities under the QF threshold (80MW in most cases) are typically older facilities. Many of them received their QF status in the 2000's and many before that, so the date field would necessarily be very wide.

Library: check "All Listed Below"

Text Search: enter "Mendota"

Document Type: on first row select Class "Appl/Petition/Req" and Type "Qualifying Facility Application or PURPA Energy Utility Filing;" on second row select Class "Order/Opinion" and Type "Commission Order Opinion"

(Leave other parameters at the default settings)

Using these search parameters (excluding the date) will produce forty-one results. Among the results will be found both an MBR authorization letter dated March 3, 2005 and a more recent QF self-certification filing dated May 24, 2007. The earlier MBR authorization letter indicates that the Mendota generation facility is a 50-megawatt wind facility in Illinois ultimately owned by Gamesa Energia SA. Since then, however, ownership of the facility changed. According to the more recent QF self-certification filing, the current owner is Babcock & Brown Wind Portfolio Holdings 1 LLC. (The Class A membership interests are owned by EFS Wind Holdings I LLC ("EFS") and Wachovia Investment Holdings ("Wachovia"). EFS is wholly-owned by General Electric Credit Corporation, a 100% owned subsidiary of General Electric Company. Wachovia is 100% owned by Everen Capital Corporation. The Class B membership interests are owned by B&B Wind Portfolio 1 LLC. Babcock & Brown Wind Partners US LLC ("BBWPUS") is the sole owner of B&B Wind Portfolio 1 LLC. BBWPUS is entirely owned by BBWP (US) Pty Ltd and BBWP (US) 2 Pty Ltd, which are each wholly and directly owned by Babcock & Brown Wind Partners Limited, a publicly traded company on the Australian Stock Exchange.)

Mendota has been chosen as an example to demonstrate the scope of the ownership interests available through FERC's e-Library.

With knowledge of the facility owners, the REC owner should proceed to Step 3.

Because it is not known if Koda has market-based rate authority or self-certified as a qualifying facility, enter the following basic information as the search parameters in FERC's e-Library Advanced Search:

Category: check "Submittal" and "Issuance"

***Date:** see notes above regarding Mendota if the type of facility is known

Library: check "All Listed Below"

Text Search: enter "Koda"

Document Type: on first row select Class "Appl/Petition/Req" and Type "Qualifying Facility Application or PURPA Energy Utility Filing;" on second row select Class "Order/Opinion" and Type "Delegated Order"

(Leave other parameters at the default settings)

Search using these parameters, which produce seven results. Among the results will be found both an MBR authorization letter dated November 25, 2008 and a QF self-certification filing dated October 21, 2008. Both documents indicate that the Koda generation facility is a 23.4 megawatt bio-mass generation facility in Minnesota ultimately owned by Rahr, a Delaware corporation, and Shakopee Mdewakanton Sioux Community, a federally recognized sovereign Indian tribe.

Note that the MBR letter also indicates that Koda is a Category 1 Seller. 18 CFR 35.36(a)(2) provides that:

(2) Category 1 Seller means a Seller that:

(i) Is either a wholesale power marketer that controls or is affiliated with 500 MW or less of generation in aggregate per region or a wholesale power producer that owns, controls or is affiliated with 500 MW or less of generation in aggregate in the same region as its generation assets;

(ii) Does not own, operate or control transmission facilities other than limited equipment necessary to connect individual generating facilities to the transmission grid (or has been granted waiver of the requirements of Order No. 888, FERC Stats. & Regs. ¶31,036);

(iii) Is not affiliated with anyone that owns, operates or controls transmission facilities in the same region as the Seller's generation assets;

(iv) Is not affiliated with a franchised public utility in the same region as the Seller's generation assets; and

(v) Does not raise other vertical market power issues.

While the characteristics of a Category 1 Seller do not explicitly satisfy Section 16-115D(a)(3.5) of the Public Utilities Act, they are indicative of a generation facility's status.

With knowledge of the facility owner, the REC owner should proceed to Step 3.

For both the Mendota and Koda examples, other search parameters can certainly be used and may produce fewer results to review. For purposes of these examples, however, we have tried to “keep it simple” knowing that with more experience with FERC’s e-Library a REC owner seeking facility ownership information will learn to refine searches.

Step 3

This step involves confirming whether any state public utility commission (“PUC”) regulates the rates of the generator or any parent company. In 2009, the US Department of Energy published a document entitled “List of Covered Electric Utilities’ under the Public Utility Regulatory Policies Act of 1978 (PURPA).” The document lists of all utilities regulated by each state and can be found at https://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/PURPA_2009.pdf The document also specifies the entities over which the state does not have ratemaking authority. If more current information is deemed necessary, Platts annually publishes its “UDI Directory of Electric Power Producers and Distributors.” A sample of the contents of Platts’ directory is available at <https://www.platts.com/IM.Platts.Content/downloads/udi/eppd/eppddir.pdf>. Platts’

directory is available for purchase at <https://www.platts.com/products/electric-power-producer-directory>. With the use of these searchable documents, a REC owner can determine whether the generator of the REC, and any parent company thereof, is under the rate making authority of any state. If the generator or a parent company is listed as an entity subject to the rate making jurisdiction of a state, the inquiry ends and RECs from that generator should not be considered eligible for the Illinois market. If the generator or a parent company is not listed as an entity subject to the rate making jurisdiction of a state, the inquiry ends with the conclusion that RECs from that generator should be considered eligible for the Illinois market.

Using the Department of Energy's 2009 publication, none of the owners associated with Mendota are identified as rate regulated by any state.

As a result of following these steps, CSG believes that RECs from Mendota are eligible for use in Illinois under Section 16-115D(a)(3.5). Certification pursuant to ICC and IPA rules and/or practices is the next step.

Using the Department of Energy's 2009 publication, none of the owners associated with Koda are identified as rate regulated by any state.

As a result of following these steps, CSG believes that RECs from Koda are eligible for use in Illinois under Section 16-115D(a)(3.5). Certification pursuant to ICC and IPA rules and/or practices is the next step.

Summary of Facility Status Determination Process

By use of above described process, we can ascertain:

- 1) The ultimate parent of the facility;
- 2) For those RECs tracked by M-RETS, whether the facility owner has been identified as an investor owned utility;
- 3) Whether the ultimate parent of the facility is a Category 1 Seller, meaning that it:
 - (i) Is either a wholesale power marketer that controls or is affiliated with 500 MW or less of generation in aggregate per region or a wholesale power producer that owns, controls or is affiliated with 500 MW or less of generation in aggregate in the same region as its generation assets;

(ii) Does not own, operate or control transmission facilities other than limited equipment necessary to connect individual generating facilities to the transmission grid (or has been granted waiver of the requirements of Order No. 888, FERC Stats. & Regs. ¶31,036);

(iii) Is not affiliated with anyone that owns, operates or controls transmission facilities in the same region as the Seller's generation assets;

(iv) Is not affiliated with a franchised public utility in the same region as the Seller's generation assets; and

(v) Does not raise other vertical market power issues; and

4) Whether the ultimate parent is listed as a rate regulated utility in a state or states.

Evaluating the presence or absence of these key data points describing the facility would an interested party strong evidence as to whether or not the facility received support from rates regulated by a State or States.

B. MEETING PERCENTAGE-BASED RPS TARGETS

1. To incent the development of new resources outside the Initial Forward Procurement requirements and the Adjustable Block Program, how should the Agency consider balancing short-term REC procurements for meeting annual RPS percentage goals with procurements of multi-year commitments for RECs? In responding to this question, please consider that the eligibility requirements under the revised RPS may reduce the availability of eligible RECs from existing projects, potentially necessitating the development of new generation.

CSG's answer is organized in the following manner:

- Overview of Reasoning for Hybrid Duration Procurements
- Benefits & Rationale for Hybrid Duration Procurements
- Sources of RECs for Hybrid Duration Procurements
- Mechanism for Administering Hybrid Duration Procurements

Consistent Short-Term Procurements (Hybrid Duration) to Complement Multi-Year Procurements

CSG believes that both short-term and multi-year procurements have their place in the context of a robust and successful LTRRPP. A consistent short-term procurement strategy could be designed to complement the IFP and ABI's. Short-term procurements would enable the development and inclusion of technologies besides wind and solar such as hydro, biogas and biomass which would result in more baseload renewable capacity; thereby enhancing grid reliability. Also, with the majority of these other renewables types being smaller and more resource driven in their location they would also arguably contribute to more grid resiliency. By this we mean that these other renewables are more likely to be located near their feedstock and their load which likely means at the outer nodes of the electric distribution system.

Constructing a market mechanism in the form of hybrid-duration procurements would provide liquidity and support for various "odd-lott" projects and RECs sources that would complement the structured, but homogenous supply provided by long-term supply contracts.

Other markets such as PJM and NEPOOL have greatly benefited on the expectation of forward markets, but not necessarily from a long-term off-take from the ultimate consumer of the RECs. Long-term procurements have many risks that can be mitigated by short-term procurements over which IPA would reserve the right to determine the best implementation strategy based on market circumstances.

Benefits & Rationale for Hybrid Duration Procurements

1) Reduced market risks to ratepayers

- Federal tax rates – Lower tax rates would likely result in less new renewables build all else equal given the impact of tax credits on finance of new projects. This could make it more expensive for a typical wind or solar resource to be built in a given year for certain types of investment grade investors. This may necessitate the development of projects which rely on unique niches or circumstances such as state tax incentives/abatements, novel renewable waste feedstocks, etc. Short term procurements could benefit these projects which may require support from RECs, but not necessarily 15 years worth. This is an important way that short term procurement could contribute to cost-effective acquisition of renewable resources.
- Current ramp-down of ITC & PTCs – Similar impact as tax rates above.
- Low REC prices in PJM – Similar impact as tax rates above, but could provide for demand volatility if PJM becomes supply constrained in 2020 and beyond.
- Ohio Wind setback reduction (State Regulatory Changes)– This is an example of state regulatory uncertainty that is in flux right now that could produce year to year supply volatility on PJM/MISO. Excess supply in Ohio could allow for more cost effective Illinois and adjacent state resources to become available with very little notice. Having a mechanism for Illinois to take advantage of these short term changes in market dynamics would be beneficial to ratepayers.
- Higher interest rates – Similar impact as tax rates above.

2) Reduced project risk to ratepayers

There could be a balancing of REC price with delivery risk. Existing projects have very little risk of delivery.

3) Enhanced grid resiliency

Short term procurements could be used to identify projects which has additional ancillary benefits which contribute to grid resiliency.

4) Enhanced grid reliability

Short term procurements of to be determined duration would be able to focus more effectively on smaller projects from technologies which are potentially less intermittent in nature than wind & solar.

5) Incent technologies besides wind and solar

Balance other technologies such as hydro, biogas, etc. with wind/solar.

6) Incent project developers with a higher tolerance for risk

Aggregation of small projects is key and its very challenging from a credit standpoint for small projects to bid into these procurements for long duration.

Smaller projects from other technologies don't have the ability many times to participate in procurements in order to build the projects. The projects are often built based on unique circumstances and end of up having a higher tolerance for risk than large wind and large solar projects. These small projects should not be penalized for their tolerance for risk.

One might say that if they build the project without RECs then they didn't need RECs in the first place. This is in fact not true because perhaps they had a lower return on investment threshold and a higher tolerance for risk than a large scale solar and wind developer.

So, the net result is that you have these smaller, riskier projects that are outside the norms and that likely cannot compete in the LTRP with the large wind and solar developer for which the regulation was crafted. There should still be a market for them on an ongoing basis to bid into in order to compensate them for their tolerance of risk.

7) Increased participation from projects/developers with less than investment grade credit

However with the development of a liquid forward market would come with listing of an exchange traded product on an exchange such as ICE. This would draw market participants in the form of market makers; many of which would be investment grade.

Buying strips forward at minimum leads to incent development. In this way some of the long term risk could be passed from the state and utilities to market participants who have a much larger portfolio of risks and are in fact investment grade.

8) Incented development of projects with less sophistication than those participating in the long-term procurements

Sources of Hybrid-Duration Procurement RECs

The diversity of the sources of RECs which would be available in a short-term procurement environment and which would complement long-term sources is worth highlighting.

1. Distributed generation projects which over generate
2. LTRP projects which over generate
3. Supplemental PV systems rolling off original contracts
4. Adjustable block projects which over generate
5. Existing wind and solar projects in Illinois and adjacent states
6. New & existing projects with a higher tolerance for risk
7. New & existing projects from alternate technologies (small hydro, biogas, biomass, landfill gas)

Mechanism for Administering Hybrid-Duration REC Procurements

The mechanism that we would propose for a complementary short-term procurement process would be as such:

Contract Duration – IPA would reserve the right to procure between one and five year contracts based on market conditions. CSG would initially propose three-year procurements. Should serve as a market-centric mechanism for filling the gaps in the long term procurement. IPA should reserve the right to determine duration of contracts and other procurement specific details.

Non-Identified Systems – IPA would reserve right to procure contracts which involved solely non-identified systems or a mix of non-identified and identified.

A strategy for balancing long and short-term procurements would be to allow short term procurements to be bid in without the explicit identification of systems. This way whatever the mismatching of supply with demand might be there would be an inherent market mechanism in the form of an incentive to aggregate the odd lot, mostly smaller generators (diversifying risk). This way the unique and not well formed supply could be met with a consistent buyer ready to provide liquidity for both existing facilities, as well as new.

Limited Banking Allowed – CSG proposes that banking would be allowed in the early years (just as it is currently allowed for ARES compliance) and that after RY19 banking would fall in line with the practice ultimately established under the LTRP, but still for no more than 3 years. This

will likely be necessary in the early stages of the program before confidence is built in the market that the process will result in consistent pricing and demand for new and existing projects.

Adjacent states limited to PJM/MISO sited – As we discuss in the next section we believe that procurement of adjacent states should be limited to facilities sited within or interconnected to PJM/MISO.

Design should allow attainment of RPS% goals if capital is available – Whatever the ultimate format is chosen the possibility that % RPS requirements should be reachable is key to implementing a procurement strategy which acknowledges the full intent of the regulations and all the priorities therein.

Carve Outs for Facilities Which Meet Resiliency & Reliability Goals – Specifically, CSG proposes to carve out a category which might incent smaller systems (which might contribute to enhanced resiliency) and facilities with higher capacity utilization factors (which might contribute to enhanced reliability).

2. Should the IPA develop distinct procurements that target specific renewable generating technologies beyond wind and solar? And if so, what technologies?

See answer to question # 1 above.

C. ADJUSTABLE BLOCK PROGRAM

Blocks

1. What approaches should the IPA consider for determining the size of blocks? What are the advantages/disadvantages of having a larger block size as opposed to a smaller block size?

The IPA should look to previous Illinois procurements to determine block sizes. Specifically the SPV and 2017 DG procurements are a helpful predictor of the size and quantity of systems that will be applying for RECS. We recommend that the IPA look at all systems that bid into the block and not just the ones that received a winning bid when evaluating the size of interest in the market.

It is important that the initial blocks of each category include capacity for the backlog of systems that began to build up starting the day the law was passed and will continue to build up until the opening of the initial blocks.

Even more important than the block size is that the price change between blocks be small and predictable. There should not be a significant change in the return on investment to the system owner as the program transitions from one block to another. It is also very important that the next block open up as soon as the previous block closes. Even if the IPA's budget is exhausted for the time period, it is important for projects to be able to gain entry in the next block and hold their spot in line for when more money is allocated.

2. Should the category for systems between 10 kW and 2 MW be subdivided into distinct blocks? And if so, what are the appropriate break-points (e.g., 100 kW, 200 kW, 500 kW) between categories, and why?

There are massive differences in installation and development costs between 11kW and 2MW. It is vital that this is broken up into tiers and a REC price adder is given based on the size of the system.

CSG agrees with the size distinctions made in the Illinois Solar Energy Associations (ISEA) Comments. They are included below for reference:

- “(1) 0 kW to less than 10 kW
- (2) 10 kW to less than 25 kW
- (3) 25 kW to less than 250 kW
- (4) 250 kW to less than 500 kW

(5) 500 kW to 1 MW

(6) 1 MW to less than or equal to 2 MW”

Additionally to maintain continuity and simplicity we recommend that size divisions in other parts of the program match the size divisions for REC pricing. For example if the divisions listed above are adopted the development milestone requirements should change at 250 or 500 kW not 200 kW.

3. Should the initial block or blocks have a different structure than subsequent blocks to account for expected pent up demand?

The initial opening of the first blocks in each category should be a soft open. All systems that are submitted in the soft open should be treated as equal in the first come first serve basis. We recommend that this soft open period last for the first two weeks of the initial block’s opening. This will help to avoid a situation where everyone is waiting to hit submit at 8:01.

4. What criteria should be used to prioritize projects within a block when applications exceed the remaining available capacity in a block? Should the projects be prioritized on a first-come first-served basis or by other criteria?

We support first come first serve allocation of RECS. The requirements to gain entry to a block needs to be sufficient to prevent overly speculative systems from entering the block in the first place. The first come first serve basis can be determined by a timestamp on the submission of the system documents to the program administrator.

There should also be a period to cure any deficiencies or problems with the submission without loosing the spot in the queue. We recommend that this period is two weeks.

5. How should the Agency handle the transition between blocks? Should a block close automatically upon being filled? Or should a block remain open until a predetermined date? Upon a block being closed, should the next block open immediately, or should there be some delay?

Subsequent blocks should open immediately after the previous block is filled or closed. Even if there is no budget yet allocated to the new block it should open and allow systems to line up for when the budget is allocated in the next fiscal year (or other time when it can be allocated to the block).

Prices

6. Should the ABP REC prices be based on a cost-based model which takes into account the revenue requirements for new projects in Illinois, or should it be based on market observations of pricing data as well as developments in other jurisdictions?

See answer to part C of this question.

6a. For the cost-based approach please provide recommendations for data inputs that should be considered for the model. If there are publicly available models that could be used as a template, please provide information about those models.

We agree with the Illinois Solar Energy Association's comments for this question. For reference they are listed below:

- **“System Components.** ISEA encourages the IPA to utilize a stakeholder process to capture the following differences in price or cost factors, including but not limited to:
 - Equipment costs (modules, inverters, meters, etc.);
 - Labor costs (including organized labor and labor increases);
 - Interconnection costs (including increases);
 - Permitting costs (will vary based on jurisdictions);
 - Soft cost proxy or buffers to account for overhead and cost to entry, such as customer acquisition costs that may be higher at beginning of ABP;
 - Operation and maintenance;
 - Changes in other national incentives or impacts of tariffs (e.g., Investment Tax Credit step down or elimination, or solar trade case impacts);
 - Electricity prices (accounting for variability in territory); and
 - Considerations regarding hitting the Net Energy Metering cap and how any new tariff structures, including smart meter tariff, impact the cost-benefit of solar.
- **Cost of Renewable Spreadsheet Tool.** NREL in partnership with the Sustainable Energy Advantage, LLC has developed a Cost of Renewable Spreadsheet Tool (“CREST”) to utilize a series of inputs as described above to determine the various costs that a solar system will entail. If this model were to be considered as a mechanism to develop appropriate REC prices (in addition to historic data from solar procurements and market data), then ISEA highly recommends the tool should be completed with stakeholder input.”

6b. For the market observations approach, please identify the jurisdictions that could be considered, and any significant differentiators between those jurisdictions and Illinois that should be used to adjust results.

There are a number of other REC markets that could be used as a reference, but none fit the requirements of the ABI program as closely as previous procurements run in Illinois for similar products.

We especially encourage the IPA to look at results from the SPV procurement for comparable market based price points. Even though the duration and size categories do not match up perfectly with the ABI, the payment structure and revenues to the system owners will be very similar. We would also recommend that the IPA look at all systems bid into the procurement not just systems that received winning bid.

When looking at REC markets in other states we also encourage the IPA to look at REC + power prices. This will help to give the IPA a fuller understanding of the revenue per MWh that is required in other markets to produce robust growth.

6c. Does the methodology for determining REC pricing have to be either cost-based or market observation based, or can it be a combination of both? Are there any other approaches that should be considered?

Both methods should be used by the IPA to determine block prices, but not necessary in the same way with the same weight. The cost based methodology will give the IPA a good case for the minimum incentive level required spur some solar development. However due to the variety of business models, installation cost variables, system sizes, and changing market conditions it will be impossible to accurately model all scenarios in a cost basis. Instead costs should be used as a check to make sure that the market based incentive estimations are in the right ballpark for a given system size. Additionally a cost based approach also does not give any indication about what the build rate will be at a given return to system owners.

Market based REC price models will help the IPA understand build rates associated with differing incentive levels. While the data is somewhat limited the IPA should look at different winning REC prices in previous Illinois procurements and the effect that price difference had on both system identification and energization rates.

7. How should the approach for determining REC prices take into account geographic differences in price or cost factors, e.g. local labor/land costs etc.? How narrowly or broadly should geographic factors be considered?

There should be no geographic adders to start, but the IPA should reserve the right to create a geographic adder at a later date to help incentivize areas that are under-represented.

8. Besides geography and system size, are there other factors that should be considered to create differentiated pricing?

We recommend that the initial program does not include other differentiating factors, but that the IPA reserves the right to incorporate adders for certain project types at a later date, if certain desired projects are under-represented in the applications for the initial blocks.

The IPA should use the general priorities of the Act:

From the preamble of Public Act 099-0906

(1) the State should encourage: the adoption and deployment of cost-effective distributed energy resource technologies and devices, such as photovoltaics, which can encourage private investment in renewable energy resources, stimulate economic growth, enhance the continued diversification of Illinois' energy resource mix, and protect the Illinois environment; investment in renewable energy resources, including, but not limited to, photovoltaic distributed generation, which should benefit all citizens of the State, including low-income households; and

Project Development Process

9. How much time should be allowed between system application/contract approval and when a system must be energized? The time allowed could take into account issues like (i) the seasonality of applications, (ii) delays in permitting, interconnection, (iii) equipment availability and etc. Should this time vary by size of system, geographic location, or interconnecting utility?

In the SPV procurement identified systems had/have a 12 month development period with an option to extend for 6 months due to delays in permitting, interconnection, or similar issues. This timeline has been, and should remain appropriate for systems above 25kW. We recommend that this timeline is maintained for systems above 25kW.

For system less than 25kW we recommend that systems are energized and registered on a REC tracking system before they are able to enter a procurement block. Reducing the entire process to one step will mitigate all risk of systems entering a block and/or getting paid for RECS that do not get developed.

This requirement for systems less than 25kW will significantly reduce the administrative workload for all parties involved. Breaking up the application to get in a block, proof of hitting milestones, and proof of energization into different steps significantly adds to the time and manpower needed to administer the program. Simplifying the application, approval, and contracting of systems all to one step will streamline the program greatly without having a significant impact on system owner's

decision making process. This will also reduce the cost per system for the system administrator, aggregators, installers, and system owners.

The main caveat to this one step approval for small systems is that REC price changes between blocks are minimal and do not significantly alter the system's payback if the block price changes during the development process.

10. What type of extensions to a guaranteed in-service date should be allowed, and what additional requirements should there be for extensions?

See answer to question # 9 above.

11. What information about a system should be required for a system to be qualified to participate in the program (e.g. site control, local permitting, interconnection status, etc.)? Should the requirements be different for smaller systems (e.g., under 10 kW) than larger systems? Should the requirements be different depending on whether the system is being interconnected with an investor-owned utility, a municipal utility, or a rural electric co-op?

For systems under 25kW we recommend that the IPA uses energization and registration on a tracking system as the requirement for entering a block. We recommend that the documents used for proof of energization under the SPV procurement are used for the ABI as well:

- (i) Interconnection Agreement;
- (ii) Certificate of Completion of Interconnection or comparable document;
- (iii) Net metering application approval letter; (iv) Final system inspection confirmation;
- (v) PJM-EIS GATS/M-RETS system registration application and approval letter;
- (vi) permission to operate letter; or:
- (vii) other relevant documentation

It is important that there are multiple documents that can be used to make this proof. As has been seen in the SPV procurement, certain utilities and municipalities can be difficult to obtain finalized documents from and can cause a significant hold up in the application process.

Systems above 25kW should show proof of their intention to move forward with construction of the project. There should be multiple acceptable proof of intention as with proof of energization.

These system requirements should remain the same regardless if the system is interconnected to an IOU, a muni, or a coop.

12. What development deposit/credit requirements should there be in addition to any program fees? And for how long should such requirements run?

See Answers above for systems less than 25kW.

For larger systems collateral requirements similar to previous procurements run by the IPA are appropriate. A bond that is fully refunded with the first REC delivery is not a significant barrier or burden for systems that have the intention to move forward with development. But a non-refundable bond payment does serve as a barrier to entry for systems that are not committed to moving forward with construction. In our experience it is the usually bond payment, not the documentation required, that weeds out systems that are speculative in nature and are not committed to moving forward with construction.

13. Should there be intermediate project milestones to help ensure that projects that have reserved RECs out of a block are successfully developed, and that closure of blocks due to all RECs being allocated is effectively managed? If so, how should milestones and performance standards vary between smaller and larger projects?

For systems less than 25kW see answer to #11.

Larger systems should have at least one intermediary target to hit after 6-8 months after they enter the block. Depending on the system type and location there are a number of different relevant milestones. We recommend that multiple documents or proofs be acceptable to meet this benchmark.

14. For the Supplemental Photovoltaic Procurement, inverter readings were allowed for systems below 10 kW, and revenue grade meters were required for larger systems. How should these standards be updated for the ABP?

We recommend that our answer to this question is reviewed in conjunction with our answer to the question below about clawback provisions.

Productions estimates, with an annual meter read to verify accuracy, are the best method of REC generation for systems under 25kW. Attaining meter reads, especially manual meter reads, from systems this size is both a large burden to aggregators and big risk to long term delivery of RECS. Without future payments to incentivize systems owners to send in meter reads it is highly likely that will be many issues with REC reporting. There is also not a difference in the number of RECS generated by the system and delivered to the contracted utility in this method when compared to monthly meter reads. As long as at least once a year a meter read is used to verify the production estimates, the annual REC production will be the same for the system as if meter reads were submitted monthly. There would at most be slight differences in the months that REC

generation occurs, but not in the total amount of generation for a given year. Production estimates also average out systems that under and over perform across the utilities entire portfolio. This also makes REC deliveries much more predictable year over year for the utilities.

Systems greater than 25kW should be required to have remote online monitoring that can be accessed by the system's aggregator. The online monitoring should meet the accuracy standards currently used by the IPA for this system size, +/- 2%.

The reasons for requiring online remote monitoring are the same as listed above for smaller systems, but with larger systems the requirement for online monitoring is a much lower capital cost for the system.

Clawback Provisions

15. What clawback provisions would be appropriate for ensuring that RECs are delivered while not creating potentially prohibitive additional costs or burdens?

We fully recognize the risks of REC delivery created by upfront REC payments. Because of this we encourage the IPA to look at mitigating this risk with a multifaceted approach that includes, but is not limited to clawback provisions.

The first step is mitigation of REC generation risk. See our answer to question # 14 above for our recommendation here.

The second step is risk mitigation of REC delivery and REC arbitrage risk. This can be mitigated by clawback provisions and/or collateral that applies to both aggregators and system owners. The use of aggregators and proper qualifications to become an aggregator greatly reduces the risk of RECS being generated, but not delivered to the contracted utility. If REC generation is handled by the steps above the aggregators should share in responsibility for REC delivery. However RECs that are not generated for reasons outside of the aggregator's control (i.e. no meter reads from a system owner) should not be cause for clawbacks against or a draw on collateral from the aggregator.

The third risk is poorly maintained and installed systems. This is the major risk that should be addressed by clawback provisions directed at the system owner. The system owner has more control over these risks of REC generation as system size increases. We recommend that the clawback provisions get more stringent as system sizes increase and that the system size tiers used are the same tiers used to differentiate REC prices. Missed generations from systems that do not maintain an internet connection for automatic reporting of meter reads or that generate their own RECS should also fall under this third category.

We would also like to draw a distinction between RECS that are not delivered due to error or negligence by system owner or aggregator and RECS that are not delivered because they are sold into another market. Intentionally selling RECS that were already sold into the ABI program is an intentional manipulation of the system and the punishment for this should be much harsher than other REC delivery failures.

16. What would be reasonable circumstances to allow for the waiving of clawback provisions? (e.g., fires, severe weather, etc.)

17. Should clawback provisions vary based on system size? If so how should these provisions vary?

18. How should clawback provisions carry over when a system and/or system location is sold?

The clawback provisions should carry forward to the new system owner. The recommendations made in #14 should help to lessen the burden on the new homeowner. It should also be one of the roles of the aggregator to maintain continuity in REC generation, reporting, and delivery as system ownership changes.

Consumer Protections

19. What consumer protection elements should the IPA consider adopting as part of the ABP program? How should those elements differ between distributed generation and Community Solar?

See answer for question 21

20. Should the ABP require the use of a standard disclosure form? If so, what elements should that form include?

See answer for question 21

21. Are there examples from other states of model approaches to consumer protection, and/or lessons learned regarding insufficient consumer protections?

We agree with the Illinois Solar Association's (ISEA) recommendations to adopt SEIA's code of ethics. These recommendations are outlined ISEA's comments.

We would also like to recommend that there be different consumer protections required for Illinois Solar for All than for the general LTRRP. Low Income communities require unique protections and regulations that are both unnecessary and overly restrictive for other market segments.

D. COMMUNITY SOLAR

Geographic Considerations

1. Should the IPA consider taking steps to encourage projects to be located geographically closer to subscribers? If so, what steps should be considered?

IPA should reserve the right to offer adders to REC price for geographic areas which have low levels of development. These adders should be implemented, if necessary, after a set % of a block is filled or a set time period. We recommend that a geographic adder is evaluated after the first block is 50% full.

2. How can geographic diversity be ensured?

The IPA should implement a REC price adder for community solar systems located in geographic areas that are under represented. See above for method.

Project Application Requirements

3. Should Community Solar projects have different application requirements than a comparably sized distributed generation project? What level of demonstration of subscriber interest should be required prior to approving an application from a Community Solar project?

We think that the IPA should reserve the right to create a requirement or an adder for higher level of subscription at project application even if there is no such requirement for entry into initial blocks.

4. How should co-location of Community Solar projects be addressed in light of the definition of community renewable generation projects that is capped at 2 MW?

While there are benefits from economies of scale to be found by co-locating community solar projects Public Act 099-0906 specifically states that a "Community renewable generation project" be "limited in nameplate capacity to less than or equal to 2,000 kilowatts." This suggests that the intent of the legislation is not to have a few very large community solar arrays, but to have smaller ones distributed throughout the state. There should be some circumstances where co-location of community solar arrays is allowed, but this should be done in a limited manner to preserve the intent of the law.

To clarify this point further, co-location of community solar arrays is different from co-locating arrays of differing types. Other solar arrays of different types at same location not counted toward

community solar capacity. For example, if a university that has a DG array that delivers RECS under the SPV procurement wants to install a community solar array for its faculty and staff to subscribe to, the existing DG array should not be counted toward any co-location capacity cap that is put on community solar arrays.

Community Solar Blocks

5. Should the design approach for blocks for Community Solar vary from that used for Distributed Generation (e.g., size of blocks, criteria for prioritizing applications)?

The design between blocks should be as similar as possible to ensure the program is predictable, easy to administer, and easy to participate in across all system types.

6. What would be reasonable assumptions to make for the cost of acquiring and maintaining subscribers? How will these costs be expected to vary over time (e.g., the difference between initial subscriber recruitment and managing churn rates)? How will these costs differ between managing residential and commercial subscribers?

7. Should the value proposition to the customer for a subscription to a Community Solar project be more, or less, attractive than for a comparable sized DG system at the customer's location.

Due to different power prices, capacity charges and timing, credit risks, costs of capital, available space, and a number of other factors it is impossible to create a perfect balance between DG and Community Solar incentives. It is even difficult to evaluate the difference in value proposition between the two in anything but a very narrow circumstance. There will always be some customers better served by a DG system and some better served by a community solar subscription. It will unnecessarily overcomplicate the program to focus too much on the interaction between the two incentives.

We recommend that the IPA focus on each segment separately. It is important that the Community Solar REC prices incentivize Community Solar and the DG REC prices incentivize DG systems.

If there is a great disparity in the rate that the initial blocks are filled the IPA could utilize their ability to adjust REC prices to balance out the build rates across system types. No additional balances should be necessary.

Development Milestones

8. Should the time allowed for Community Solar project development be different than for comparably sized Distributed Generation systems?

Due to added complications, credit requirements, and administrative work required for multiple subscribers relative to a single single counterparty community solar projects should have some additional time relative to a similar sized DG project. We recommend that they have an additional 3-6 months to hit initial development timelines and the same requirements afterwards.

9. What project development milestones should be required to demonstrate sufficient levels of subscriber interest before a contract may be terminated?

The initial block should the same requirements as a comparably sized DG system. This consistency will help the market move smoothly and avoid additional administrative work and complications. The premium price of power (and the adder recommended in our answer to #11) should serve as ample motivation for project developers to find subscribers for their community solar arrays.

However, we recommend that the IPA reserve the right to add in requirements if any issues arise.

Residential versus Commercial Interest

10. What, if anything, should the IPA consider to ensure robust residential participation in Community Solar?

See answer to question #11.

11. Should REC pricing vary based on the portion of the project that is residential? How can this be verified, and what would be required over time to ensure ongoing residential participation?

Customer acquisition, credit risk, ongoing administrative requirements and other factors increase the cost of residential subscribers relative to commercial and industrial subscribers to community solar arrays. These costs are partially offset by the higher price of power paid by residential customers, but not fully. This requires extra incentives to be offered to residential subscribers.

In order to keep the program simple, effective, and easy to administer we recommend that the REC price be the same for all types of community solar projects and an adder be paid out based on the percentage of residential customers subscribed to the array. This adder should be paid out annually based on the quantity of MWh delivered to residential subscribers. The annual deliveries

of residential MWh should be submitted to the IPA by the system owner and verified by the interconnecting utility.

This method avoids the issues that would arise if different REC prices were paid upfront then subscriber bases change over time. This also allows the IPA to change the value residential adder over time to encourage robust participation from residential customers, even in community solar arrays that are already installed.

12. Should project application/viability requirements be different based on the mix of residential and commercial customers?

This requirement should not be set in initial blocks, but we recommend that the IPA reserves the right to make this a requirement for later blocks, if there is not diverse participation. Also, if there is not broad enough participation the adder mentioned in our reply to question #11 should be modified before requirements for system types are implemented.

13. Are there additional considerations that should be made for projects that are entirely subscribed with commercial customers, or entirely subscribed with residential customers?

No special considerations should be made for these projects.

E. ILLINOIS SOLAR FOR ALL PROGRAM

CSG does not wish make any recommendations on the ISFA program, but instead we defer to other market participants with more expertise in this area.