<u>ATTACHMENT 3 TO APPLICATION FOR REHEARING</u>

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

The Illinois Power Agency	**)**	
	)	
Petition for Approval of the	**)**	**Docket No. 13-0546**
2014 IPA Procurement Plan pursuant to	**)**	
Section 16-111.5(d)(4) of the	**)**	
Public Utilities Act.	**)**	

DIRECT TESTIMONY ON REHEARING OF

ERIC THUMMA

ON BEHALF OF

THE RENEWABLES SUPPLIERS

<u>RENEWABLES SUPPLIERS EXHIBIT 3.0</u>

JANUARY 21, 2014

Q. Please state your name, present position, and business address.

A. My name is Eric Thumma. I am Director of Policy and Regulatory Affairs for the Iberdrola Renewables LLC. My business address is 1693 Beacon St., Number 3, Brookline, MA 02445.

Q. What are your duties and responsibilities as Director of Policy and Regulatory Affairs for Iberdrola Renewables LLC?

A. As Director of Policy and Regulatory Affairs, I am responsible for the businesses policy, regulatory, and legislative affairs in the Eastern and part of the Midwestern United States. My responsibilities focus on renewable portfolio standard policy, wind energy project siting, taxation, and other policies, legislation, and regulations related to local and state siting of wind energy projects.

Q. Please describe your educational background and business experience.

A. I graduated from the University of Pittsburgh in 1994 with a B.A. degree in Political Science and in 1996 with an M.P.I.A. degree in Public and International Affairs. I was employed from 1996 to 2007 by the Commonwealth of Pennsylvania and the Pennsylvania Department of Environmental Protection ("PA DEP"). I was Director of PA DEP's Energy Bureau from 2003 to 2007. During that period, I worked on legislation mandating Pennsylvania's electricity suppliers to purchase a certain percentage of their electricity from eligible renewable energy sources. The bill, The Alternative Energy Portfolio Standards Act, was passed and signed into law by Pennsylvania Governor Edward G. Rendell in 2004. I joined Iberdrola Renewables in 2007 as Director of Policy and Regulatory Affairs and continue in that role today. In February 2010, North American Wind Power published an article, co-written with my colleague Peter Toomey, on the necessity of long-term renewable energy contracts in restructured electricity markets entitled: <u>Wanted: Stability in Restructured Electricity</u>

Markets. In December 2012, I authored the comments of the Mid-Atlantic Renewable Energy Coalition before the Pennsylvania Public Utility Commission's Retail Markets Investigation. The comments identify the challenges of total reliance on short-term procurement for renewable energy development.

Q. Have you previously testified in regulatory proceedings?

A. Yes, as Director of PA DEP's Energy Bureau, I testified before the Pennsylvania Public Utility Commission. The topic of my testimony was advocacy for the implementation of Smart Meter technology. I was also a witness for Iberdrola Renewables' subsidiary, Community Energy, Inc., in an administrative proceeding seeking approval for a retail voluntary green energy tariff for Allegheny Energy in Pennsylvania. I have submitted written testimony and comments in whole or in part before regulatory commissions and legislatures in Illinois, Maine, Missouri, New Hampshire, New York, and Pennsylvania. I have also presented oral or written testimony before legislatures in Delaware, Illinois, Maine, Maryland, Pennsylvania, and Ohio. This testimony has covered topics such as general renewable energy policy, renewable portfolio standards legislation, and state renewable energy siting requirements.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the group of intervenors referred to as the Renewables Suppliers. The companies comprising the Renewables Suppliers are listed on page 1 of their Application for Rehearing and Reconsideration in this docket. Each of the Renewables Suppliers, through their project companies, has entered into one or more long-term power purchase agreements ("LTPPAs") with one or both of the Illinois electric utilities to supply renewable energy resources.

Q. What is the subject matter of your direct testimony in this rehearing proceeding?

A. My testimony addresses the public policy need for long-term contracts for new electricity generation, specifically renewable energy generation necessary to meet the Illinois Renewable Portfolio Standard ("RPS").

Q. In addition to your prepared direct testimony, which is identified as Renewables Suppliers Exhibit 1.0, are you presenting any other exhibits?

A. Yes, I am also submitting exhibits identified as Renewables Suppliers Exhibits 3.1 and 3.2 which were prepared by me or under my supervision and direction.

Q. What is the Illinois RPS?

A. The Illinois RPS requires electricity suppliers to provide a certain percentage of retail electricity supply from eligible renewable energy resources. The RPS requires an increasing percentage of renewable energy supply up to 25% in 2025. The requirements for utilities and Alternative Retail Electric Suppliers ("ARES") are slightly different. Utilities must source 75% of their RPS requirements from wind energy, whereas ARES must source 60% from wind. Utilities also have an additional distributed generation requirement which does not apply to the ARES.

Q. How much wind energy will be required to meet the Illinois RPS?

A. Meeting the Illinois RPS requires significant investments in new wind farms. According to my analysis (see Renewables Suppliers Exhibit 3.1), the RPS required approximately 2,291 MW of wind capacity for compliance year 2013-14 and will require at least an approximate 7,972 MW[1] of wind capacity for compliance year 2025-26 (depending on whether utilities or ARES are serving load, given that different wind energy requirements apply to each type of electricity supplier, as described in my immediately preceding answer). As a result significant additional investment in new wind farms will be

[1] Assumes that utilities are serving 34.6 percent and ARES are serving 56.9 percent of electricity demand respectively per Energy Information Administration 2012 data.

necessary to meet the RPS. In order for this to be realized, investors in wind energy facilities must be confident they will recover this investment plus a reasonable, risk-weighted rate of return.

Q. What are wind energy's revenues streams and the basic economics of financing a wind energy project?

A. Wind energy projects receive three primary revenue streams[1]: (1) federal tax incentives[2] in the form of the production tax credit which is equal to $23/MWh, but has expired except for projects which have already "begun construction;" (2) wholesale energy, sold at a market determined price, and; (3) renewable energy certificates ("REC"). A REC is created for each MWh of electricity generated by a qualifying renewable energy facility. Revenue from RECs and wholesale energy must cover the delta between the revenue necessary for a wind energy project to recover its costs and make a reasonable, risk-weighted rate of return on investment and the total value of federal tax incentives.

As a result, the combination of REC values plus energy revenues is essential for wind energy project revenue adequacy. If REC values plus energy revenues are not sufficient, then wind energy projects will fail to achieve revenues which are adequate to recover costs and make a reasonable rate of return.

Q. Why are long-term contracts important and necessary for renewable energy projects?

A. A wind farm's variable costs are very low compared to other forms of conventional generation, particularly fossil fuels, because wind farms have no fuel costs; therefore, a wind farm's variable costs are largely limited to routine operation and maintenance. The

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[1] In PJM, wind energy projects do qualify for capacity payments. However, this is generally a small portion of project revenue compared to the three primary revenue streams I have identified.

[2] Accelerated depreciation also provides meaningful economic value for wind energy projects. Generally, wind developers must find an investment partner that can utilize the tax benefits of the production tax credit and accelerated depreciation in order to finance a wind energy project.

primary cost of a wind farm is its initial capital investment. Generally, a wind farm's capital investment is amortized and recovered over a 20-year period. As a result, in order for an investor to make a rational decision to invest in a wind farm, that investor must be confident that long-term revenue streams exist sufficient to guarantee recovery of capital costs and a reasonable, risk-weighted rate of return. A fixed price long-term contract is the most efficient means by which to ensure adequate capital recovery and revenue adequacy for wind farm investments.

There are two points, by comparison, as this relates to cost recovery for conventional generation:

(1) Existing conventional generators, generally, have previously recovered their capital costs as part of a government regulated, rate-of-return vertically integrated utility model prior to electricity restructuring. As a result, conventional generators benefitted from long-term capital recovery guarantees which wind energy projects also need and seek, but such guarantees are generally unavailable in restructured electricity markets.

(2) Since existing conventional generators, generally, no longer require long-term capital recovery, most of their costs are variable. As a result, competitive wholesale energy markets which set prices based on variable costs are generally a sufficient mechanism for existing conventional generators to recover their costs.[3]

As pointed out above, neither of these conditions applies to wind energy generators. The primary costs for wind energy projects are initial capital investments which must be recovered over the long-term. Short-term wholesale energy and REC markets provide insufficient mechanisms for this recovery.

[3] Although, in PJM, even wholesale energy prices have proven insufficient for revenue adequacy for many existing conventional generators, hence the creation of the Reliability Pricing Model or RPM, PJM's capacity market.

Q. Do electricity consumers benefit from long-term contracts between wind energy projects and load-serving entities?

A. Yes, long-term contracts provide two potential benefits for electricity consumers:

(1) Lower Compliance Costs: As explained above, the primary cost of wind energy projects is capital. This tends to be amortized over 20 years (the assumed life of the project). As a result, the cost of capital is the key component in the final cost of a wind project and the levelized cost of energy ("LCOE") a wind farm must achieve to be financeable. Like any other investment, the cost of debt and equity for a capital project relates to risk – the riskier the prospects for capital recovery, the higher the cost of debt and equity. In this regard, wind energy projects generally fall into three categories:

i. Fully Merchant: fully merchant projects sell energy and RECs on the spot market where prices are determined by short-term supply and demand. This is considered the riskiest form of capital recovery and, therefore, has the highest costs for debt and equity. In fact, in many cases it may be difficult or impossible for wind energy developers to achieve project financing for fully merchant projects since banks and other lenders will not provide debt to projects without assured revenue streams.

ii. Merchant/Contract Hybrid: some wind energy projects may be able to achieve a long-term contract for either energy or RECs, but not both. An example would be New York projects which may have a 10-year REC-only contract with the New York State Energy Research and Development Authority, but no mechanism for long-term energy contracts. This structure has less risk than a fully merchant project, but still has risks and, consequently, higher capital costs than a project benefitting from a LTPPA.

iii. Long-Term Power Purchase Agreement (bundled energy and RECs): this structure is the least risky, since an LTPPA (*all other things being equal)* will be priced so that the wind energy project's cost recovery and reasonable, risk-weighted rate of return is assured. **This structure has the lowest capital costs which can be passed on directly to consumers in the form of a lower LCOE –** assuming a properly competitive process for selecting LTPPAs.

Structure	Energy Hedge	REC Hedge	Risk	LCOE
Merchant	No	No	Very High	Highest
Hybrid	No or Yes	Yes or No	High	Higher
LTPPA	Yes	Yes	Low	Lowest

To review, higher debt and equity risk = higher LCOE = higher RPS compliance costs. In order to reduce overall RPS compliance costs, regulators should closely examine the benefits of LTPPAs in terms of reduced financing costs and LCOE and, ultimately, lower costs to consumers of RPS compliance.

(2) Hedge: Generally, electricity consumers in restructured electricity markets are significantly exposed to ongoing fluctuations in wholesale electricity markets since electricity prices are set based on the variable costs of the marginal power plants. Since marginal power plants in PJM and MISO are always either coal or natural gas, electricity prices are directly linked to short-term fluctuations in commodity prices. Therefore, in the short term, unforeseen power plant outages or weather conditions or a combination of both can expose electricity consumers to electricity price spikes. Over the long term, rising commodity prices expose electricity consumers to rising electricity prices.

Prudence suggests that electricity consumers' benefit from some portion of their electricity supply coming from fixed priced resources that are immune to short- and long-term price volatility associated with fossil fuels. LTPPAs with wind energy projects provide a perfect hedge because wind energy can offer a fixed, long-term price for energy.

Q. How are Alternative Retail Electricity Suppliers ("ARES") in Illinois meeting their RPS obligations?

A. It is my understanding that ARES are primarily buying RECs on the spot market or for very short terms in order to fulfill their RPS obligations.

Q. Are short-term REC purchases an effective mechanism to support investments in new renewable energy projects?

A. No. This is demonstrated in detail in Renewables Suppliers Exhibit 3.2.

Q. Is it possible for the RPS to be achieved without long-term contracts?

A. It is unlikely that the RPS can be achieved without long-term contracts, for the reasons detailed in Renewables Suppliers Exhibit 3.2.

Q. Would adoption of the Renewables Suppliers' primary proposal make them whole under their LTPPAs?

Yes. Under the IPA Plans for 2013-2014 and 2014-2015 (as approved in this docket), utilities and the IPA (to the extent the IPA voluntarily elects to do so) purchase curtailed RECs at an imputed price calculated by the difference between the bundled LTPPA price and the projected energy price from the IPA's 2010 forward energy curve ("FEC"). (Craig Gordon's direct testimony on rehearing discusses the 2010 FEC in greater detail.) The LTPPA suppliers sell the curtailed energy under their LTPPAs into the wholesale power market. As a result, the LTPPA suppliers are short the difference between the projected energy price from the 2010 forward energy curve and the current price of energy in the wholesale power market (the Day-Ahead Locational Marginal Price) multiplied by the quantity of curtailed energy. The primary proposal addresses this shortfall, without abrogating the statutory cost cap, by ensuring that the Renewables Suppliers are paid for otherwise curtailed energy based on the price of the 2010 forward energy curve.

The primary proposal recommends that curtailments should not apply to the **energy** portion of the LTTPAs. As a result, utilities would pay the LTPPA suppliers for energy that is being curtailed under the currently-adopted approach, based on prices from the 2010 FEC. The utility (using its accumulated Alternative Compliance Payment ("ACP") funds collected in respect of sales to its customers served on hourly-pricing tariffs) and the IPA (using the funds in the Renewable Energy Resources Fund ("RERF")) would continue to purchase curtailed RECs at an imputed price calculated by the difference between the LTTPA contract price and the price of energy from the 2010 FEC (as they do currently). These two sources of revenue (energy plus curtailed RECs) taken together fulfill the full contract price of the LTPPA.

Q. Does the Renewables Suppliers' secondary proposal make them whole under their LTPPAs?

Yes. As explained in my immediately preceding answer, under the current approach to implementing curtailments, the LTPPA suppliers are short the difference between the projected price of energy in the 2010 FEC and the current price of energy in the wholesale power market, multiplied by the quantity of curtailed energy. The secondary proposal addresses this problem by calculating the imputed REC prices paid by the utility and by the IPA (if it voluntarily chooses to do so) for curtailed RECs as the difference between the LTTPA contract price and the current price of energy in the wholesale power market. This approach makes the LTPPA suppliers whole by eliminating the shortfall created by the difference in price between the projected price in the 2010 FEC and the current price of energy in the wholesale power market. It is also identical to the financial settlement mechanism specified in the LTPPAs. Since curtailed RECs are paid for by the utility out of its accumulated hourly ACP funds and by the IPA out of the RERF, the statutory cost cap is unaffected and not abrogated.

Q. Why is it important for the Renewables Suppliers to be made whole under their LTPPAs?

In enacting the RPS, the Illinois legislature has set a goal of 25% renewable energy supply by 2025. This will require substantial capital investment – as I described earlier in this testimony. Potential investors in renewable energy projects will only initiate these investments if they believe they can recover their capital costs and earn a reasonable, risk-weighted rate of return. If the Renewables Suppliers and other suppliers under the LTPPAs are not made whole under their existing contracts, this will signal to investors that they must either earn higher returns in order to account for the potential regulatory risks of doing business in Illinois, which will raise RPS compliance costs and exacerbate RPS cost cap challenges, or, they will seek to deploy limited capital in other jurisdictions with less risk.

The Renewables Suppliers' primary proposal and secondary proposal provide the option to make the LTPPA suppliers whole and achieve revenue adequacy for their projects, without abrogating the statutory cost cap or negatively impacting eligible retail electricity customers, who are not asked to pay more than they otherwise pay under the LTPPAs. As a result, the Renewables Suppliers have presented a solution that achieves the dual policy goal of assuring RPS compliance without harming electricity customers.

Q. Does this complete your prepared direct testimony?

A. Yes, it does.

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Public Utilities Act.	)	

VERIFICATION OF ERIC THUMMA

STATE OF MASSACHUSETTS	)	
	)	SS
COUNTY OF NORFOLK	)	

Eric Thumma, on oath, states that he is Director of Policy and Regulatory Affairs for Iberdola Renewables LLC; that he prepared the foregoing "Direct Testimony on Rehearing of Eric Thumma on Behalf of the Renewables Suppliers," identified as Renewables Suppliers Exhibit 3.0 and the accompanying Exhibits 3.1 and 3.2; that he adopts Renewables Suppliers Exhibit 3.0 as his Direct Testimony on Rehearing in ICC Docket 13-0546; that the information set forth in Renewables Suppliers Exhibits 3.0, 3.1, and 3.2 is true and correct to the best of his knowledge, information and belief; and that if called to testify in ICC Docket 13-0546 and asked the questions shown in Renewables Suppliers Exhibit 3.0, he would give the answers shown therein.

OFFICIAL SEAL
ZINA A PARKS
NOTARY PUBLIC-OREGON
COMMISSION NO. 480991
MY COMMISSION EXPIRES AUGUST 22, 2017

Eric Thumma

Subscribed and sworn to before me
this 21 day of January, 2014.

Notary Public

Calculation of Additional MW of Wind Generation Needed to Meet Illinois Requirement in 2025

Utilities Requirements

Compliance Year	Demand Growth	Electricity Demand MWh*	Utility Demand	RPS Requirement %	RPS Requirement MWh	Wind Requirement %	Wind Requirement MWh	**Wind Requirement MW*** **
2011-12	0.009	131,324,859	49,672,837	6.0%	2,980,370	0.75	2,235,278	**729**
2012-13	0.009	132,506,783	50,087,564	7.0%	3,506,129	0.75	2,629,597	**858**
2013-14	0.009	133,699,344	50,538,352	8.0%	4,043,068	0.75	3,032,301	**989**
2014-15	0.009	134,902,638	50,993,197	9.0%	4,589,388	0.75	3,442,041	**1,123**
2015-16	0.009	136,116,762	51,452,136	10.0%	5,145,214	0.75	3,858,910	**1,259**
2016-17	0.009	137,341,812	51,915,205	11.5%	5,970,249	0.75	4,477,686	**1,460**
2017-18	0.009	138,577,889	52,382,442	13.0%	6,809,717	0.75	5,107,288	**1,666**
2018-19	0.009	139,825,090	52,853,884	14.5%	7,663,813	0.75	5,747,860	**1,875**
2019-20	0.009	141,083,516	53,329,569	16.0%	8,532,731	0.75	6,399,548	**2,087**
2020-21	0.009	142,353,267	53,809,535	17.5%	9,416,669	0.75	7,062,501	**2,303**
2021-22	0.009	143,634,447	54,293,821	19.0%	10,315,826	0.75	7,736,869	**2,523**
2022-23	0.009	144,927,157	54,782,465	20.5%	11,230,405	0.75	8,422,804	**2,747**
2023-24	0.009	146,231,501	55,275,507	22.0%	12,160,612	0.75	9,120,459	**2,975**
2024-25	0.009	147,547,585	55,772,987	23.5%	13,106,652	0.75	9,829,989	**3,206**
2025-26	0.009	148,875,513	56,274,944	25.0%	14,068,736	0.75	10,551,552	**3,441**

ARES Requirements

Compliance Year	Demand Growth	Electricity Demand MWh*	ARES Demand	RPS Requirement %	RPS Requirement MWh	Wind Requirement %	Wind Requirement MWh	**Wind Requirement MW*** **
2011-12	0.009	81,652,022	81,652,022	6.0%	4,899,121	0.6	2,939,473	**959**
2012-13	0.009	82,386,890	82,419,219	7.0%	5,769,345	0.6	3,461,607	**1,129**
2013-14	0.009	83,128,372	83,160,992	8.0%	6,652,879	0.6	3,991,728	**1,302**
2014-15	0.009	83,876,528	83,909,441	9.0%	7,551,850	0.6	4,531,110	**1,478**
2015-16	0.009	84,631,416	84,664,626	10.0%	8,466,463	0.6	5,079,878	**1,657**
2016-17	0.009	85,393,099	85,426,607	11.5%	9,824,060	0.6	5,894,436	**1,923**
2017-18	0.009	86,161,637	86,195,447	13.0%	11,205,408	0.6	6,723,245	**2,193**
2018-19	0.009	86,937,092	86,971,206	14.5%	12,610,825	0.6	7,566,495	**2,468**
2019-20	0.009	87,719,526	87,753,947	16.0%	14,040,631	0.6	8,424,379	**2,748**
2020-21	0.009	88,509,001	88,543,732	17.5%	15,495,153	0.6	9,297,092	**3,032**
2021-22	0.009	89,305,582	89,340,626	19.0%	16,974,719	0.6	10,184,831	**3,322**
2022-23	0.009	90,109,332	90,144,691	20.5%	18,479,662	0.6	11,087,797	**3,616**
2023-24	0.009	90,920,316	90,955,994	22.0%	20,010,319	0.6	12,006,191	**3,916**
2024-25	0.009	91,738,599	91,774,598	23.5%	21,567,030	0.6	12,940,218	**4,221**
2025-26	0.009	92,564,247	92,600,569	25.0%	23,150,142	0.6	13,890,085	**4,530**

* Data for 2012 electricity demand from Energy Information Administration 1990-2012 Retail Sales of Electricity by State by Sector by Provider (EIA-861) http://www.eia.gov/electricity/data/state/

2012 Data

Service Provider	Retail Sales	Percentage
Utility Bundled	49,672,837	34.60%
Coops/Muni	11,570,748	8.10%
Non-utility	644,397	0.40%
Power Marketers	81,652,022	56.90%
Total Sales	143,540,004	

***Assumes 35% capacity factor

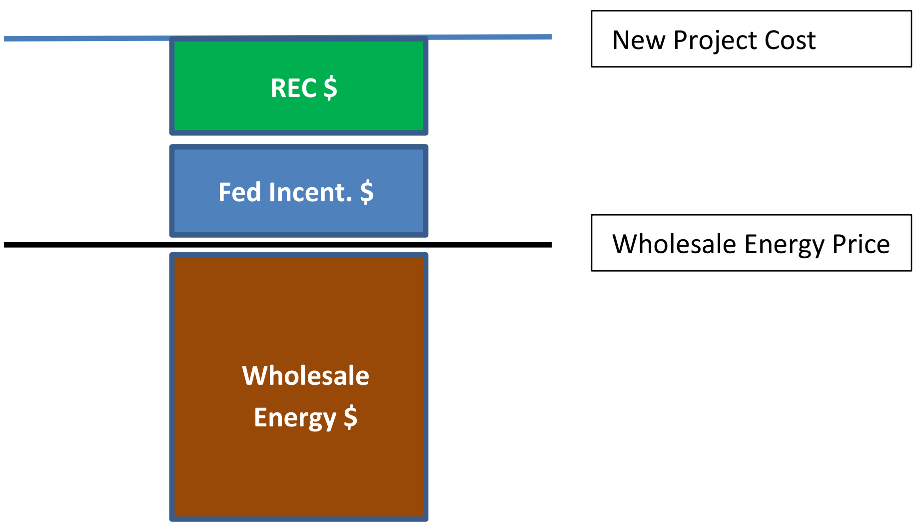
Wind Energy Necessary to Comply with the RPS

Utility Wind CY 2025-26	3,441
Utility Wind 2013-14	989
ARES Wind CY 2025-26	4,530
ARES Wind CY 2013-14	1,302
Total Wind CY 2012-13	2,291
Total Wind CY 2025-26	7,972

<u>Short –Term REC Purchases are an Insufficient Mechanism for Achieving RPS Mandates</u>

In an efficient REC ("Renewable Energy Certificate") market, a REC's value equals the difference between the value of wholesale energy and federal incentives and a new wind energy project's long-term costs and a reasonable, risk-weighted rate of return. In an efficient REC market, a REC equals:

REC = (wind energy project cost + reasonable, risk-weighted rate of return) minus (wholesale energy + federal incentives)



Renewable Energy Revenue Sources

If a REC market is not producing a price signal equal to the difference between the value of wholesale energy and tax incentives and the long-term cost of a new renewable energy project and a reasonable, risk-weighted rate-of-return then that price signal is inefficient. Going forward we shall refer to the difference between the value of wholesale energy and federal incentives and the long-term cost of a new wind energy resource and a risk-weighted, rate-of-return as the incremental cost. In an efficient market, over the long-term, a REC's value should equal the project's incremental cost.

Efficient REC Market Design: REC=Incremental Cost

The challenge of relying solely on short-term REC price signals is that REC prices will be determined by short-term supply and demand and will not necessarily produce a price reflective of incremental cost. The challenge is further exacerbated by the "thinness" of REC markets, by this we mean that REC markets have limited demand and a limited number of buyers and sellers and, therefore, lack the massive market liquidity of say the PJM energy market with hundreds of market participants on the supply and demand side, buying and selling at many different locations in the market. As a result, in a short-term REC market, prices tend to fall towards zero when supply is even slightly long, discouraging investments in new renewable generation required for RPS compliance. This is the current Illinois market condition. When the market is slightly short, prices tend to rise towards the alternative compliance payment level, creating windfall profits for generators in the short-run and price spikes that may be detrimental to consumers. Comparatively, the much more liquid PJM energy market produces far more stable pricing (ceteris parabis).

The Illinois Power Agency's first five procurements for one year wind RECs demonstrate short-term REC market price volatility. This chart examines IPA REC purchases for ComEd for IL and adjacent state wind from 2008 to 2012.

Year	Price	Type	Quantity RECs
2008	$35.72	Illinois Wind	734,735 (estimate)
2009	$21.13	Illinois Wind	821,289 (estimate)
2010	$5.00	Illinois Wind	1,507,642
2011	$1.05	Illinois and Adjacent State Wind	1,587,791
2012	$0.88	Illinois and Adjacent State Wind	1,066,792

These results led to an average weighted REC price of $9.40. In our example, this average weighted REC price would not be sufficient to encourage new renewable energy development (or, in fact, to achieve revenue adequacy for existing renewable energy investments). Therefore, presuming rational market behavior on the part of renewable energy investors, in future years REC prices must rise to well above a new renewable energy project's long-term incremental costs.

Over the long-run, total reliance on short-term REC markets may still work to encourage RPS compliance, although only if policy-makers and legislators are willing to let renewable energy investors, take the market's upside. We are highly skeptical that this is possible, further the RPS's cost-cap fundamentally constrains the amount of upside which renewable energy investors can obtain and, therefore, limits the prospects for cost-recovery in a market totally reliant on short-term REC price formation.[1]

The following series of charts will demonstrate that total reliance on short-term REC price formation will potentially discourage RPS compliance and almost certainly result in unnecessary price volatility.

[1] Limited upside is a major problem in cost recovery. PJM's cap on wholesale energy prices is one reason that its capacity market was created. Market participants, including conventional generation owners in Illinois Com-Ed, endorsing the RPM design and PJM's capacity market recognize that markets which limit upside revenue create challenges for cost recovery and revenue adequacy.

We have established that an efficient REC market produces a REC price equal to a project's incremental cost over the long run.

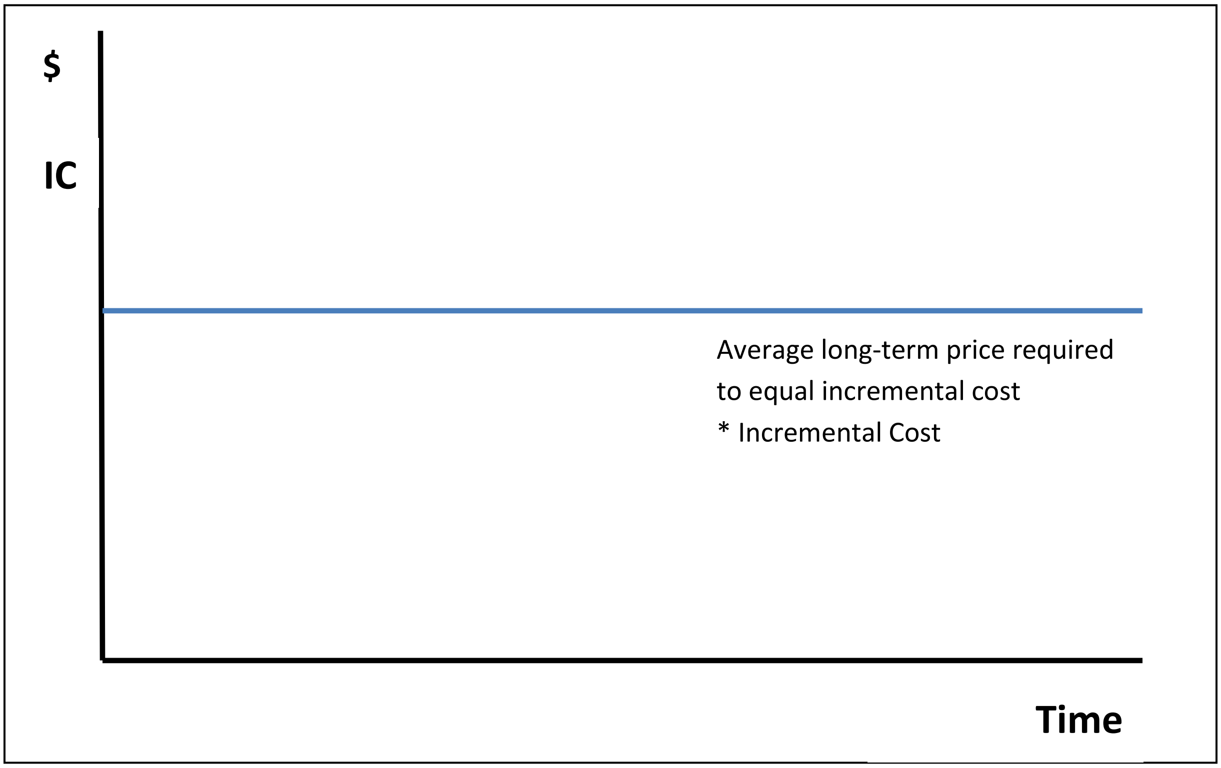


Figure 1: REC Price Required for Incremental Cost Recovery

Figure 1 demonstrates the REC price which must be achieved over the long run to equal a new renewable energy project's incremental cost and, as such, to make a new renewable energy project economic. This price is represented by the flat blue line. IC stands for incremental cost. In an efficient REC market REC prices will equal incremental costs over the long run.

Figure 2 characterizes the current state of Illinois's REC market.

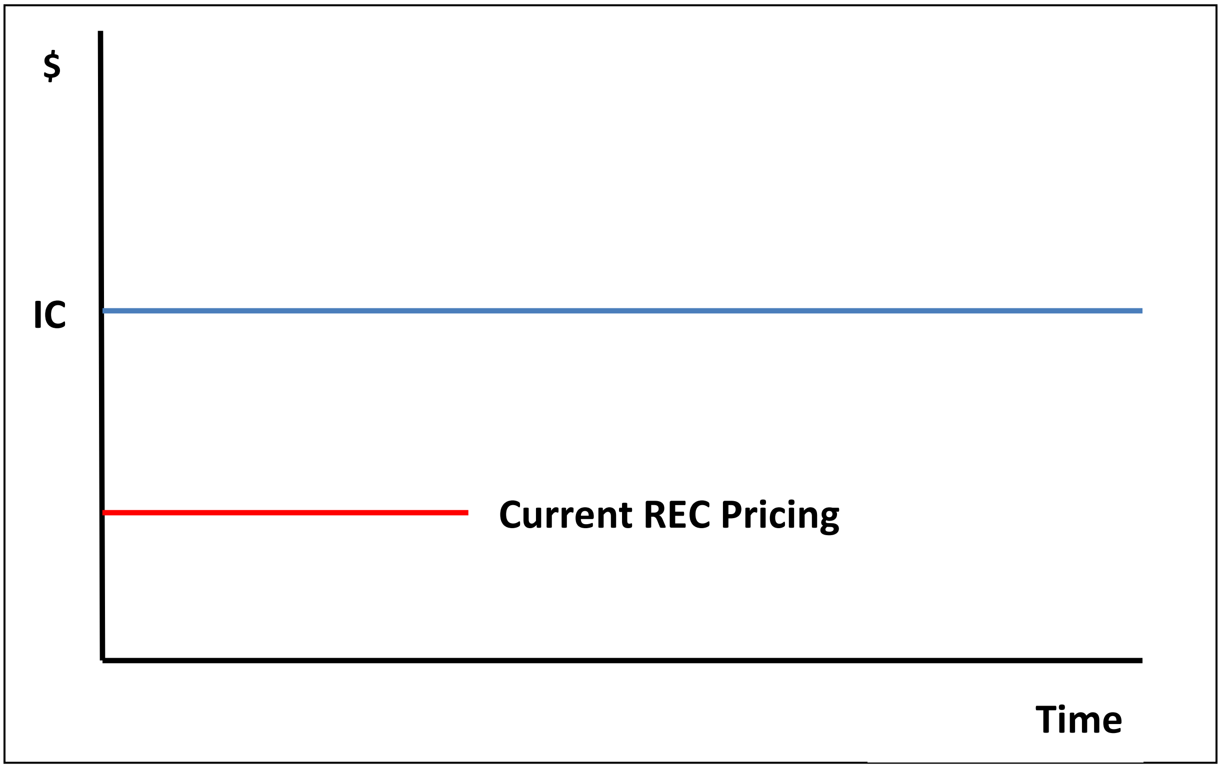


Figure 2: Current REC Prices are Below the Incremental Cost

Illinois's REC market is currently oversupplied. As expected, this results in REC prices well below the incremental cost. In an efficient market, ceteris parabis, the low price signal would discourage new investment; prices would rise in the out-years as a result, allowing existing investments to achieve their incremental costs. Rising REC prices would then encourage the additional investment necessary to meet the RPS's out-year targets. We believe that advocates of total reliance on short-term REC markets expect REC market pricing to work this way. However, as the next figures will demonstrate there are flaws in this approach that we believe makes total reliance on short-term REC markets an inefficient and ineffective approach to meet long-term, increasing RPS requirements.

Figure 3 demonstrates that in order for REC revenues to achieve the incremental costs, significant increase in REC prices must occur in the out-years.

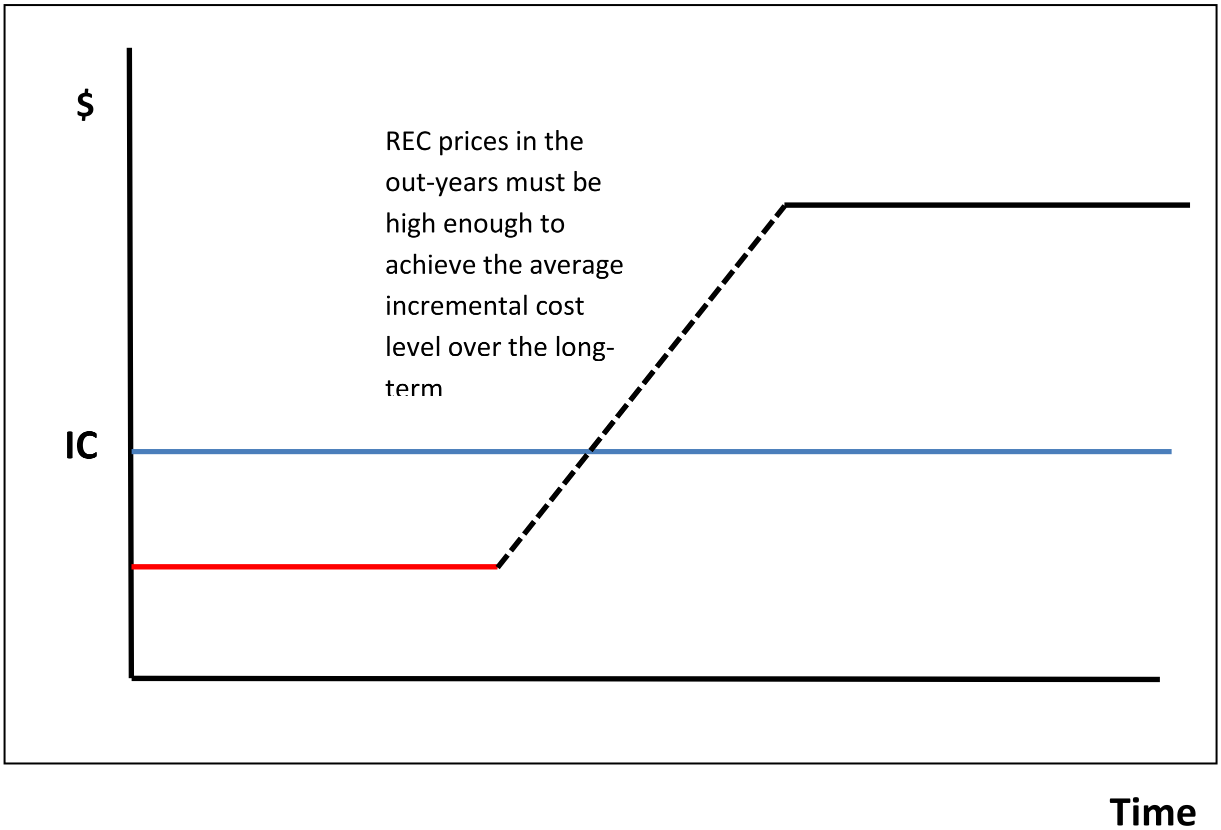


Figure 3: Out-Year REC Prices Must Rise Significantly to Achieve Incremental Costs

If prices are able to rise in the out-years to achieve a long-term average REC price that meets a project's incremental cost requirements then it is conceivable that total reliance on short-term REC markets could achieve the objective of encouraging investments in new renewable energy resources necessary to meet future RPS requirements. This would require stakeholders, such as legislators, PSC commissioners, energy suppliers, consumer advocates, and customers to accept that in some years renewable energy investors will be entitled to receive very high prices in order to recover their costs and not to seek redress of future high REC prices either through legislation or regulation.

Figure 4 presents the case that REC prices are constrained on the "upside" by the RPS cost-cap. As a result, presuming renewable energy investors are behaving rationally, achievement of the RPS targets will be endangered as REC price signals will be insufficient to encourage investments in new renewable energy resources.

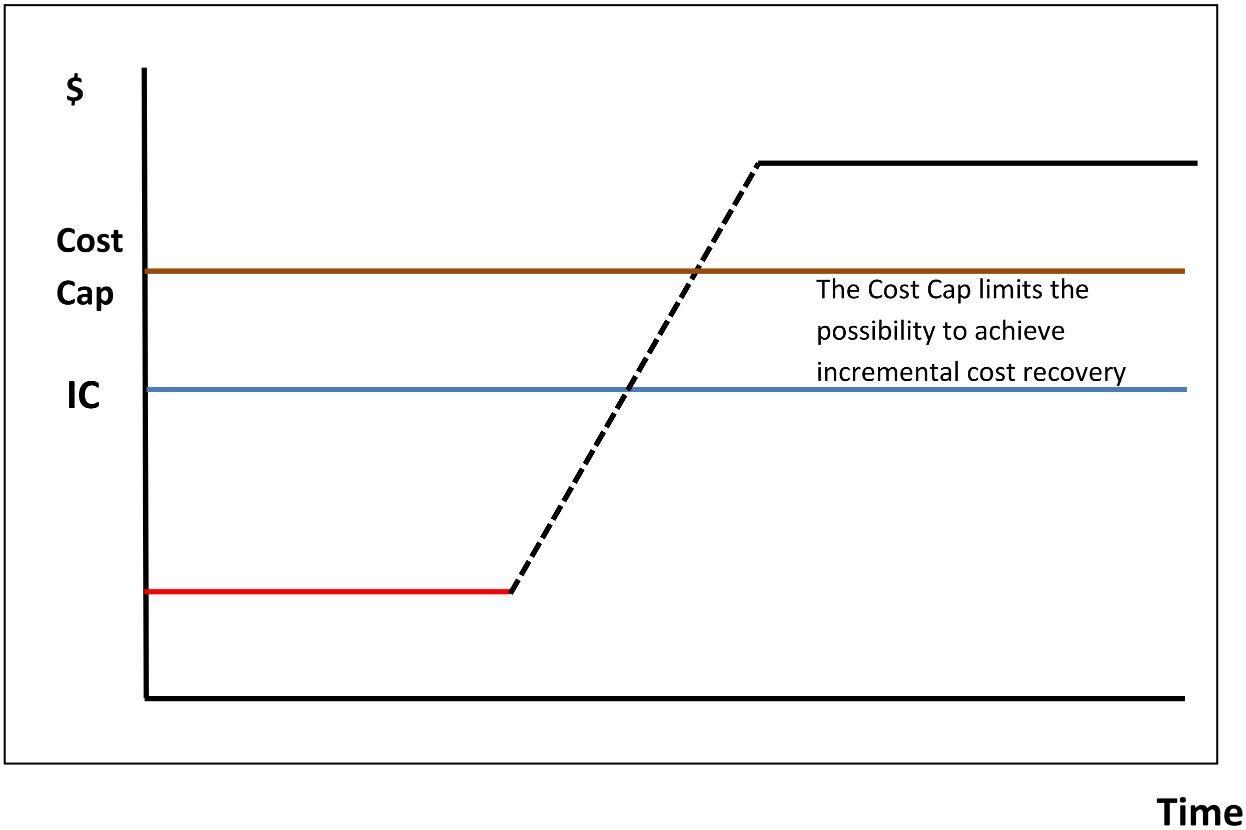


Figure 4: The Cost Cap Limits Out-Year REC Prices

The brown line added to Figure 4 represents a limitation to the upside of out-year REC revenue. In short, total reliance on short-term REC markets to obtain incremental costs is limited by the cost cap. **As a result, we believe there is a real danger that achievement of out-year RPS targets will not be achieved because renewable energy investors will be unable to recover their incremental costs (or will believe that cost-recovery is impossible due to limitations in achieving high-enough out-year REC prices to make their investment worthwhile, especially in light of the high degree of regulatory risk such project investments face).**

In this scenario, failure to achieve the RPS targets will not result because eligible wind energy resources were "too expensive," rather it would result from a simple failure of market design, easily remedied by implementing competitively-sourced LTPPAs. LTPPAs more closely align REC prices to long-term incremental costs, while reducing price volatility. In a very competitive market, in which renewable energy generators are only able to achieve recovery of their costs, plus a reasonable, risk weighted rate-of-return impacts to electricity consumers would be either the same or less over the long-run as if the market relied completely on short-term procurement, but without the volatility or regulatory risk to wind energy investors and citizens that RPS targets will not be achieved.