# Lifting the Veil on Hidden Risk in Renewable Power Purchase Agreements

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**Mr. Lance Titus** (left), Managing Director, Uniper Global Commodities, and co-author of this article, in discussion with Dr. Vince Kaminski (right), Ph.D., Professor in the Practice of Energy Management, Rice University, at the September 30, 2016 JPMCC Research Council meeting at the University of Colorado Denver Business School. Mr. Titus and Dr. Kaminski are both members of the JPMCC's Research Council.

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Renewable power purchase agreements (PPAs) have long been important enablers of renewable energy development. They are a means to both providing the revenue certainty that project developers need to secure financing for capital-intensive wind and solar projects, and giving renewable energy buyers access to the renewable energy they desire without upfront capital outlay or the need for development expertise. As with any structured transaction, these benefits come with a specific set of risks. Renewable PPAs can span fifteen years or more and their long-term value depends on the future states of the notoriously volatile physical and financial electricity markets. The intermittency and volatility of solar or wind energy produced under a renewable PPA means that, once the contract is signed, the buyer is locked into a financial arrangement over which he/she has very little control. As such, there is significant risk to the PPA buyer that adverse market moves may devolve a once attractive and prudent PPA into a liability that generates significant negative cash flow on a monthly basis.

This article, the first in a two-part series on the risks associated with renewable PPAs, focuses on how rigorous analysis to support purchase decisions can help buyers properly understand and assess PPA value and risk on a project-by-project basis. We provide a statistical description of location-specific renewable resource density and intermittency, and we demonstrate how alignment between generation intermittency and variability in locational marginal electricity prices ultimately drives PPA value. To do this, we present results from a case study based on the Pennsylvania Solar Park in Nesquehoning, PA, illustrating uncertainty in monthly settlement cash flows and the total value of energy generated under a hypothetical hub-settled virtual PPA. We also discuss how future increases in renewable penetration on the grid may potentially result in additional downside risk for PPA purchasers.

The second article in the series, to be published in the Winter 2018 edition of the *Global Commodities Applied Research Digest* (*GCARD*), will outline specific strategies for actively monitoring and mitigating downside risk for buyers entering into renewable PPAs. It will build on the case study presented in the present article and will demonstrate the risk-reduction benefits of a targeted hedging strategy, discussing how active monitoring and management of PPAs can mitigate the risk of value loss over the contract lifetime.

**Background**

Prior to 2010, electric utilities were the most common buyers or "offtakers" of renewable PPAs. Most agreements were physical deals, meaning the utility actually took title to the physical electricity produced at the metered receipt point, passing it on to its customers through existing transmission and distribution infrastructure. With demand for renewable energy rising among large corporations with aggressive sustainability targets, a new financial product called a synthetic or "virtual" PPA (VPPA) was eventually developed as a more flexible alternative to traditional physical PPAs.

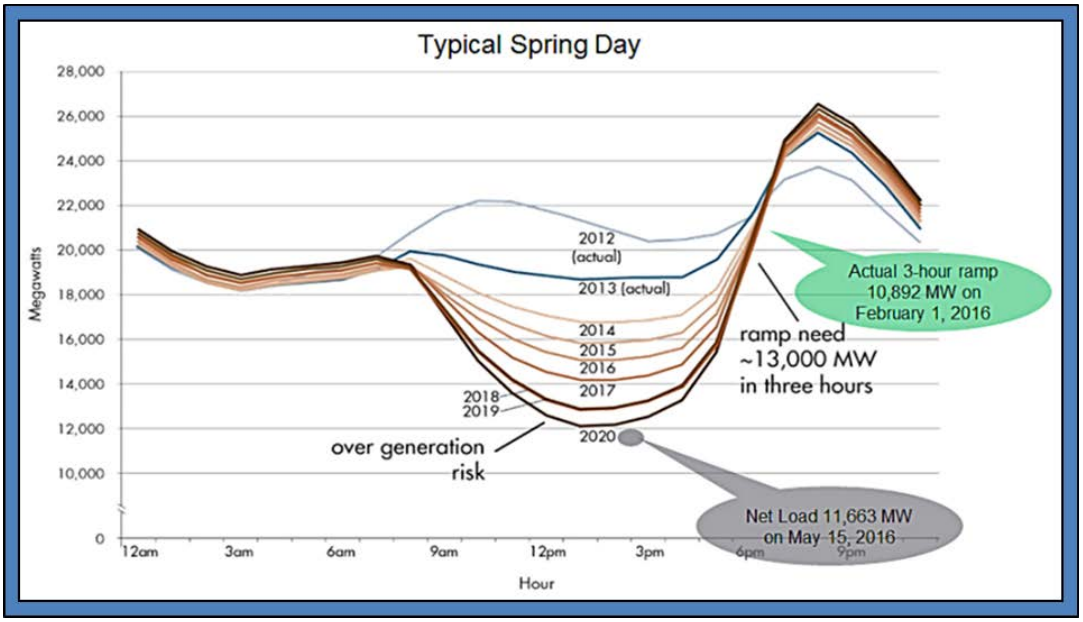
The VPPA, or "contract for differences" (CFD), provides a way for a company to acquire the renewable attributes (renewable energy credits, or RECs, and "additionality") of new wind and solar projects without having to take actual title to the physical electricity produced. This enables a company whose primary focus is not the generation and distribution of electricity to offset its carbon footprint and progress toward its renewable energy goals, while also laying reasonable claim to renewable "additionality" for its efforts. Additionality is the notion that a new renewable generation facility has been built specifically to satisfy the renewable energy demands of a particular buyer. That is, without the long-term financial commitment of the buyer to purchase the renewable generation from the facility, usually under a PPA, the facility itself would never have been placed in service. Today, additionality is an essential component of many corporate sustainability programs because it establishes a credible link between the purchaser of a PPA and the actual facility producing renewable electricity under the agreement.

VPPAs are financially settled contracts under which the buyer and seller agree to a fair price for the electricity produced by a particular wind or solar facility over a particular time horizon.[1] The electricity generated by the facility is liquidated into the wholesale power market and earns the prevailing real-time wholesale power price at the settlement location at the time of generation. The buyer and seller then exchange funds each month in the amount of the difference between the contracted PPA price and the market value of electricity sold at the settlement location, hence the term "contract for differences". When the monthly production-weighted average market price of electricity is greater than the PPA price, the buyer of the PPA receives a payment in the amount of the difference; when it is lower, the buyer must make a cash payment to the seller for the difference.

While the primary motivation for entering into VPPAs may be acquiring the renewable attributes from the associated generation, the monthly cash settlement of the CFD structure means the long-term value of the energy itself can significantly impact a buyer's future balance sheet. This value is determined in the often-volatile real-time energy markets where the price of electricity may spike up to $9,000/MWh[2] or may take on negative values that force generators to pay for putting electricity onto the grid.[3] Moreover, renewable electricity generation is inherently intermittent, meaning the PPA buyer has no control over when it is produced, particularly if the deal is contracted as unit-contingent.[4] It is not an exaggeration to state that, at the most fundamental level, a VPPA is a long-term fixed-for-floating swap in one of the most volatile financial markets in the world on real-time or day-ahead settlement of a stream of energy the buyer cannot control.

If future electricity prices rise, a VPPA may generate additional revenue for the purchaser; however, if prices fall, the deal can result in significant unexpected monthly payments. With new challenges in renewable integration such as the "Duck Curve" in California due to high levels of mid-day solar generation (see Figure 1) and the significant and consistent negative wholesale market pricing in western Texas, any PPA valuation based on simply inflating today's electricity prices into the future is lacking in analytical rigor. A decision to purchase a VPPA should be based on project-specific analysis that identifies the most prominent risks associated with both generation and price uncertainty. In turn, this analysis should be used to inform and enact a well-reasoned procurement or hedging strategy that will protect the buyer from potential downside pricing events, even if at the expense of potential future upside. Without adequate downside protection, a well-intentioned VPPA aimed at renewable energy attribute procurement may contain a hidden long-term speculative component.

**Figure 1**
**The "Duck Curve" Showing Projected Load Net of Solar within the Footprint of the California Independent System Operator (CAISO)[5]**




Note: This figure was first popularized in a report by the CAISO in 2013 and has become an iconic representation of how solar generation can significantly reduce mid-day thermal load and exacerbate evening ramping requirements. The reduction in mid-day thermal load can lead to lower (or occasionally negative) marginal prices for real-time electricity.

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## Solar VPPA Case Study

As an example of a rigorous analysis to support a VPPA purchase decision, we present a case study for the Pennsylvania Solar Park (PSP) in Nesquehoning, Pennsylvania. With a nameplate capacity of 10 MW AC, the PSP was the largest solar facility in Pennsylvania when it began commercial operation in late 2012. The location and nameplate capacity of the facility were obtained from publicly-available data,[6] and we analyzed a hypothetical virtual PPA for electricity produced by the facility.

Our analysis assumes that the contract for differences is hub-settled on a monthly basis at the PJM Western Hub, one of the most liquidly-traded electricity pricing hubs in the world. Table 1 provides additional details on the solar project and PPA terms assumed for the analysis. We note that, while our example focuses on a solar VPPA, the same analytical framework is equally applicable to VPPAs for wind and other intermittent generation technologies as well.

**Table 1**
**Pennsylvania Solar Park Project Details and Hypothetical VPPA Assumptions**

| | |
|---|---|
| **Facility Location** | Nesquehoning, Pennsylvania |
| **Latitude, Longitude** | 40.8645° N, 75.8110° W |
| **Nameplate Capacity (MW AC)** | 10 |
| **Buyer's Pro-Rata Capacity** | 100% |
| **Buyer** | iBuySolar, Inc. |
| **Seller** | Solar R Us, LLC |
| **Fixed Price ($/MWh)** | $35 |
| **Floating Price ($/MWh)** | The Locational Marginal Price at the Settlement Point in the Real-Time Energy Market as determined by the Independent System Operator |
| **Settlement Point** | PJM Western Hub |
| **Independent System Operator** | PJM |
| **Settlement Term** | 5 Years beginning at HE 0100 EPT on the Commencement Date |
| **Commercial Operation Date** | October 15, 2012 |
| **PPA Commencement Date** | January 1, 2018 |
| **PPA Contract End Date** | December 31, 2022 |
| **Performance Guarantee** | None |

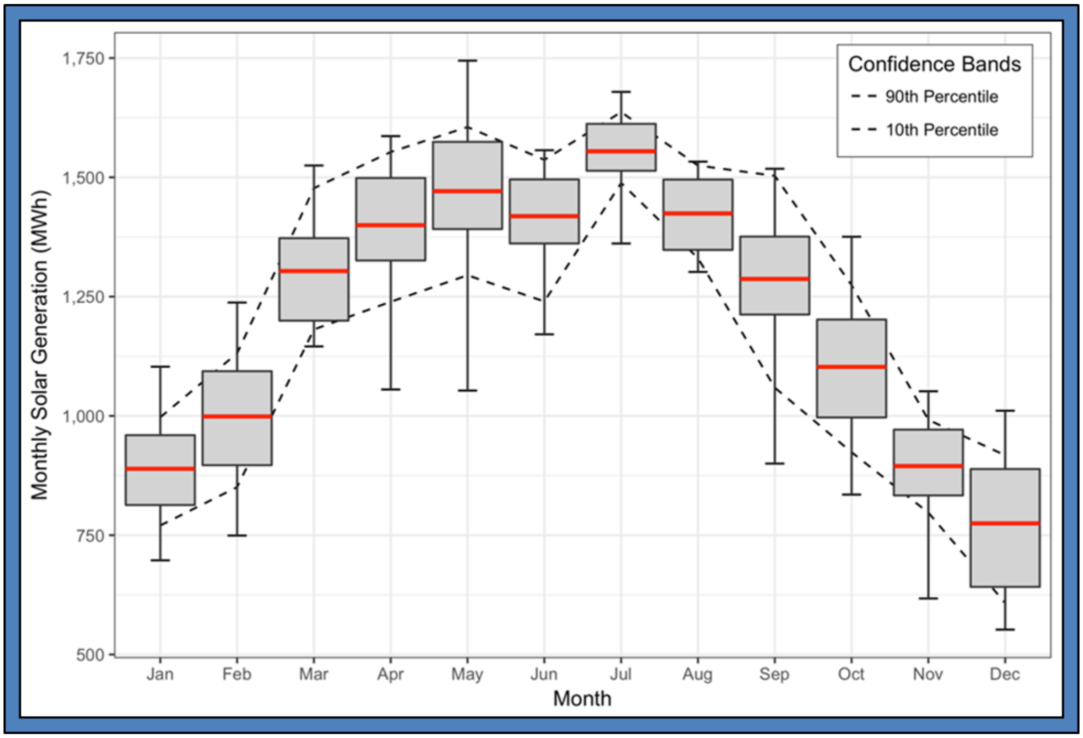
## Analyzing the Project-Specific Renewable Resource

We begin analysis of the proposed VPPA by quantifying the density and intermittency of the renewable resource at the site of the generation facility. The PSP, located in northeastern Pennsylvania, will have a significantly different generation profile than a similarly-sized solar farm in, for example, Arizona. It is important to understand how generation at the particular geographic location of the PSP will vary over the course of each year, since the total value of electricity produced under the PPA is driven by the real-time facility production. In particular, it is useful to understand the expected hourly generation shape, the uncertainty around expected generation, and how each varies seasonally throughout the year. Seasonal weather attributes such as temperature, cloud cover, rain, average wind speed, and the number of daylight hours in each day all vary widely by location. Each of these significantly affects renewable resource density, the timing of renewable energy production, and the degree of uncertainty around that production.

To analyze the solar resource density and timing for the PSP, we first collected historical hourly solar radiation data at the specific latitude and longitude of the facility. We then used this data as input into the NREL System Advisor Model to compute hourly historical facility generation, and we computed various statistics from the resulting hourly production dataset. Using a model to calculate historical facility production from historical solar radiation allowed us to estimate the energy the facility would have generated even before it began commercial operation; this yielded a larger dataset for analysis than using actual metered historical production. Such a model-based approach also allows analysis of PPAs associated with renewable generation facilities that have not yet come online.

Figure 2, Figure 3, and Figure 4 below provide summary statistics from the historical analysis of renewable resource density and timing for the PSP. Figure 2 demonstrates a strong seasonality in monthly facility generation, with expected total monthly generation declining by roughly 50% between July and December.

**Figure 2**
**Box-and-Whisker Plot Showing Variability in Historical Total Monthly Generation for the Pennsylvania Solar Park**




Note: The red horizontal lines indicate the expected value (average), upper and lower box boundaries indicate the P25 and P75 quantiles, and the whiskers extend to the minimum and maximum values of total generation for each month. All statistics are computed over the historical period from 1998 through 2015.

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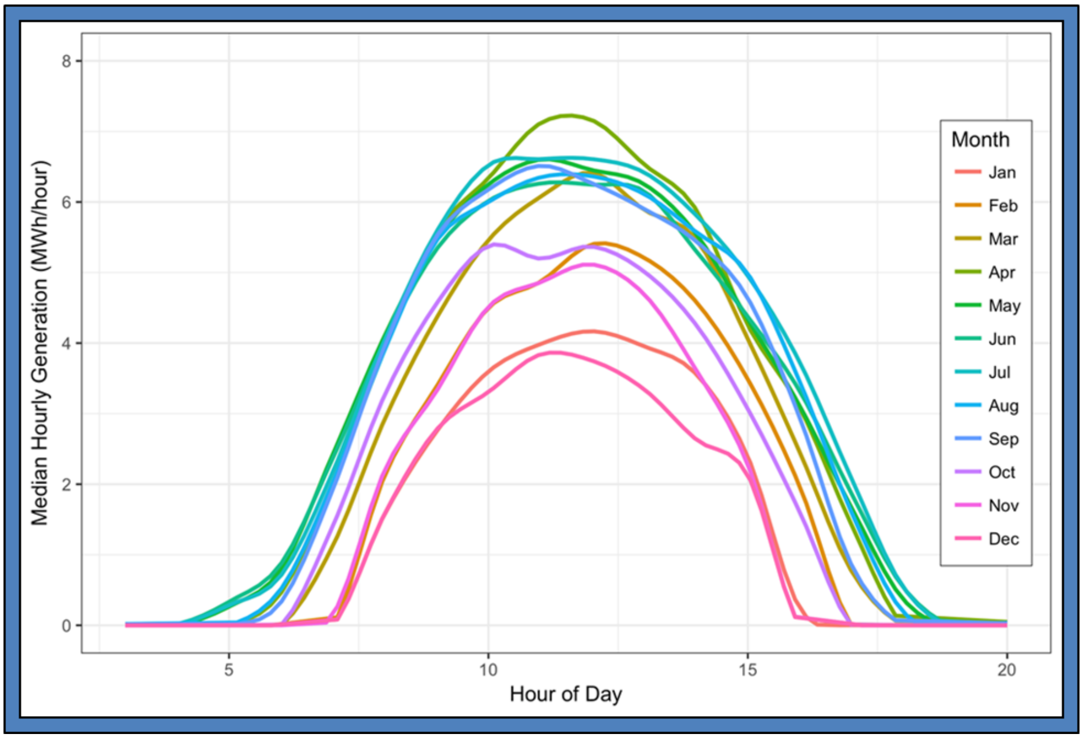
The box-and-whisker plot also nicely demonstrates the significant seasonality in monthly generation uncertainty; May and September show the greatest uncertainty as measured by the distance between the lower and upper whiskers. Significantly, while the highest expected monthly production occurs in July, the maximum production over any single historical year occurred in May at about 1750 MWh. This potential for extremely high generation in May has important implications for downside swing risk (variation in actual production of energy), which can cause significant negative monthly settlement cash flows and reduce overall PPA value. We discuss swing risk in greater detail below.

Figure 3 illustrates the seasonal variation in the diurnal generation profiles for the PSP. The curves are color-coded by month of year, and each curve represents the median generation for each hour of the day in a particular month, as computed across all historical generation data. A general seasonal trend is apparent, where months from March through September exhibit relatively commensurate generation levels while mid-day median generation falls significantly from October through February. Notably, while the total monthly expected generation is significantly higher in July than in March and September, as seen in Figure 2, mid-day median generation is much more commensurate across all of these months. This likely reflects the fact that generation during the mid-day solar peak is near system nameplate capacity from March through September, while summer total monthly generation also benefits from days with more daylight hours. Seasonal variation in the number of daylight hours is reflected in the diurnal profiles by the width of the curves for each month; as expected, median generation is positive for significantly fewer hours in the winter than in the summer.

**Figure 3**
**Pennsylvania Solar Park Diurnal Production Curve at the Median (P50) for Each Month of the Year**

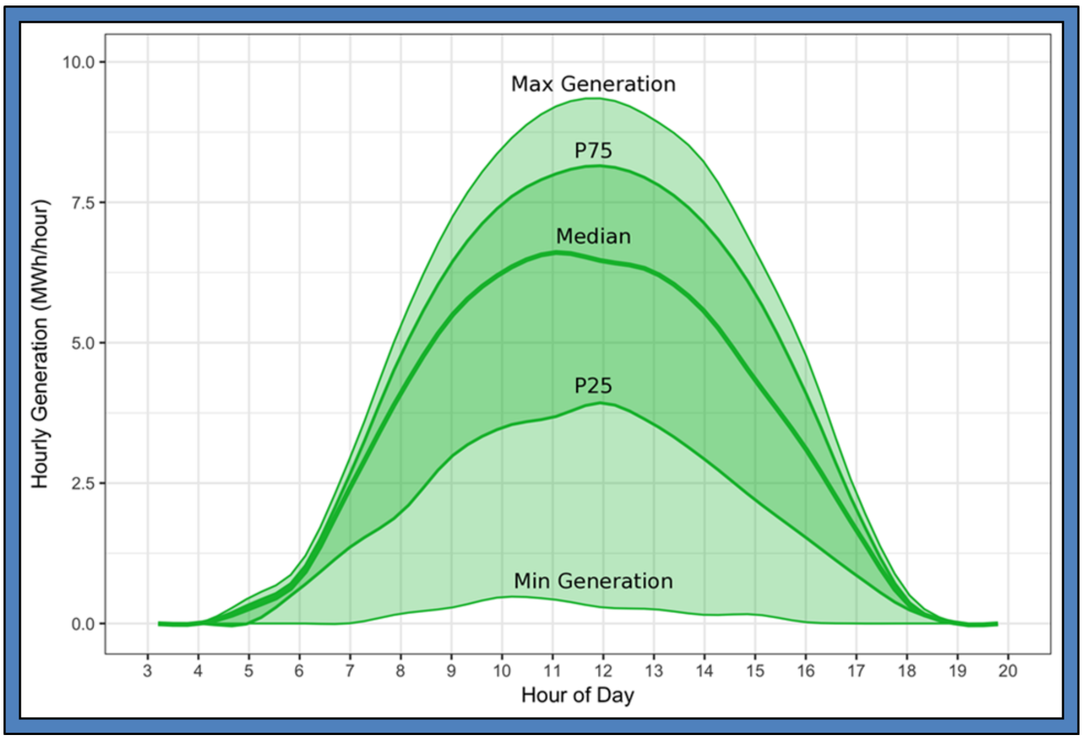



Note: The curves were constructed from 18 years of simulated historical solar generation based on hourly solar irradiance data over the same time period.

Focusing our analysis on shorter timescales reveals more variability in solar generation levels. As we disaggregate the monthly and daily generation profiles and move to the hourly level, we begin to see the true intermittent nature of the renewable resource. Figure 4 shows hourly generation statistics for the month of May, the month seen in Figure 2 to have the greatest variability in total monthly generation. Most striking in the figure is the extreme variability in production between the minimum and maximum hourly generation. Notably the upper envelope (maximum generation) for each hour is quite smooth. This is because the maximum generation is always limited by the available solar radiation in each hour; even on the clearest of days, there is an upper limit to the radiation in any given hour, and it obeys a strong and very regular diurnal pattern driven by the rotation of the earth. By contrast, the lower envelope (minimum generation) for each hour is more irregular. It is driven largely by weather patterns that obscure solar radiation and prevent it from reaching the panels. Such weather patterns are highly variable, and they impart their irregularity on the lower quantiles of hourly generation.

Finally, Figure 4 also shows that the distance between quantiles compresses as we move from minimum generation to maximum generation. This indicates that each hourly distribution of potential generation levels in May has a significant left skew. Put another way, the left tail in the distributions of hourly generation is generally longer/fatter than the right tail, which will tend to pull the expected hourly generation downward from the median. Again, this left skew is likely driven by highly variable weather events, which in any given day may decrease generation only slightly from the median or, in extreme cases, may cause the facility to generate almost nothing at all.

**Figure 4**
**May Variability in Solar Generation by Hour**




Note: Statistics were computed from 18 years of simulated historical solar generation based on hourly solar irradiance data over the same time period.

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## Simulating Renewable Generation and Market Prices

In addition to an understanding of seasonal and hourly patterns in generation and intermittency, an analysis of real-time market prices forms the other half of a comprehensive PPA value assessment. Electricity prices display strong quasi-periodic seasonal, weekly, and hourly patterns in both absolute price and in uncertainty around expected price. These patterns combine with the generation time series patterns discussed above to determine the value of the energy produced under the PPA. Since the value of energy produced by the facility is the product of generation and market price, the precise statistical manner in which uncertainty in prices and generation aligns determines the ultimate risk to the buyer.

The preferred way to investigate this statistical alignment is through Monte Carlo simulation of both hourly generation and hourly electricity prices over the PPA contract horizon. Our analysis used a historical simulation approach to create multiple hourly generation paths into the future by daily sampling of the historical data, with replacement. This approach yielded a time series of simulated hourly future generation that reflected the same statistical properties of the historical dataset, in aggregate, including seasonal and hourly fluctuations in generation and uncertainty. Each individual simulated hourly generation path also represented a plausible future outcome for the facility production.

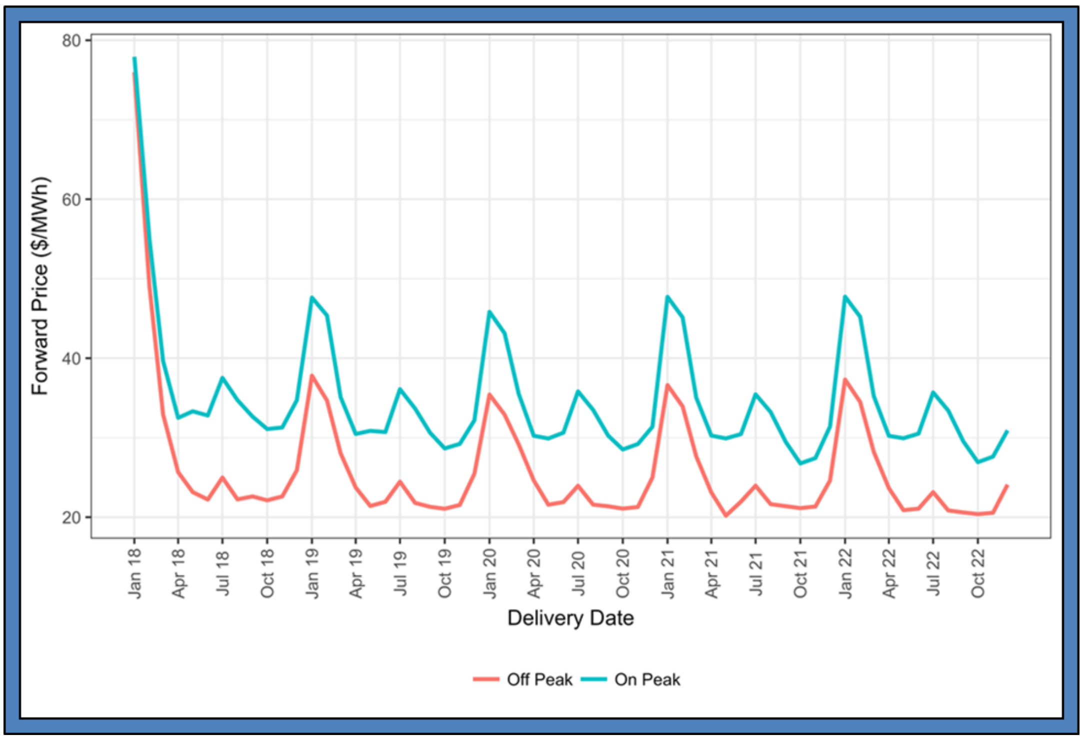
Whereas expected future renewable generation for a given month and hour of day can be reasonably well estimated through an analysis of historical data,[9] the expected future price of electricity is constantly changing in response to complex physical grid developments and financial market dynamics. One way to gain insight into the ever-changing market expectation of the future price of electricity is by examining the prices of liquidly-traded forward or futures contracts. In the case of PJM Western Hub, the settlement hub assumed for the VPPA in the present case study, exchange-traded futures contracts exist for monthly future delivery of on- and off-peak power.[10] The currently-traded futures price is a good indication of what the market believes will be the average spot price of electricity over a particular contract's delivery period. Available option-implied price volatility indications can serve as a useful guide as well.

To generate hourly simulations of future electricity spot prices, we used an autoregressive mean-reverting time series model with a jump-diffusion component. We calibrated the model against five years of historical hourly PJM Western Hub spot price history, ensuring simulated prices reflected historically-observed trends in hourly price shape, price volatility, mean reversion rate, and jump frequency and magnitude. Furthermore, we allowed each of these model parameters to vary by calendar month. The resulting price simulations provided a historically-consistent representation of the most important location-specific electricity price attributes for determining the energy component of the PPA value and inherent risk. To align these price simulations with current market sentiment, we ensured that the average simulated price in any future month was equal to the current futures contract price for that month. Enforcement of this "no arbitrage" modeling condition resulted in price simulations that were risk neutral with respect to current market expectations of the future price of electricity.

Figure 5 shows the on- and off-peak futures contract prices for PJM Western Hub power that were used in the model calibration process. Contract prices shown in the figure were as of January 12, 2018 for delivery ranging from balance-of-month through December of 2022. As can be seen in the figure, there is a very strong seasonal component to both the on- and off-peak futures prices, with more than a $15/MWh swing between the lowest-priced months and the highest-priced months for each contract. Both the on- and off-peak curves display elevated prices in the winter and summer, peaking in January and July, respectively; the winter spike is more pronounced than the summer spike in each curve. Such seasonality in electricity prices can be a key driver of value and/or risk for renewable PPAs. Additionally, there is a slight but noticeable downward trend in prices over the PPA settlement horizon, with October on-peak prices dropping almost $5 through 2022. While the downward trend may be subtle, it does reflect a market expectation that electricity prices will remain relatively stable; this expectation is essential to incorporate into any long-term PPA value and risk analysis.

Finally, it is apparent that January 2018 futures prices are much higher than January prices in all other years. This is because extremely cold weather in the northeastern U.S. caused by a "bomb cyclone" at the beginning of January 2018 placed great strain on the natural gas supply system, resulting in gas and power prices that were elevated well-above-normal levels. The high January 2018 prices in Figure 5 show the continued effects of the early-month strain on the balance-of-month power contract. Since the extreme cold was such a rare winter weather event, it was not expected to be repeated in subsequent years; accordingly, futures prices in 2019 and beyond reflected a more normal winter outlook.

**Figure 5**
**Forward Curve for PJM Western Hub On- and Off-Peak Power, as Quoted on January 12, 2018**



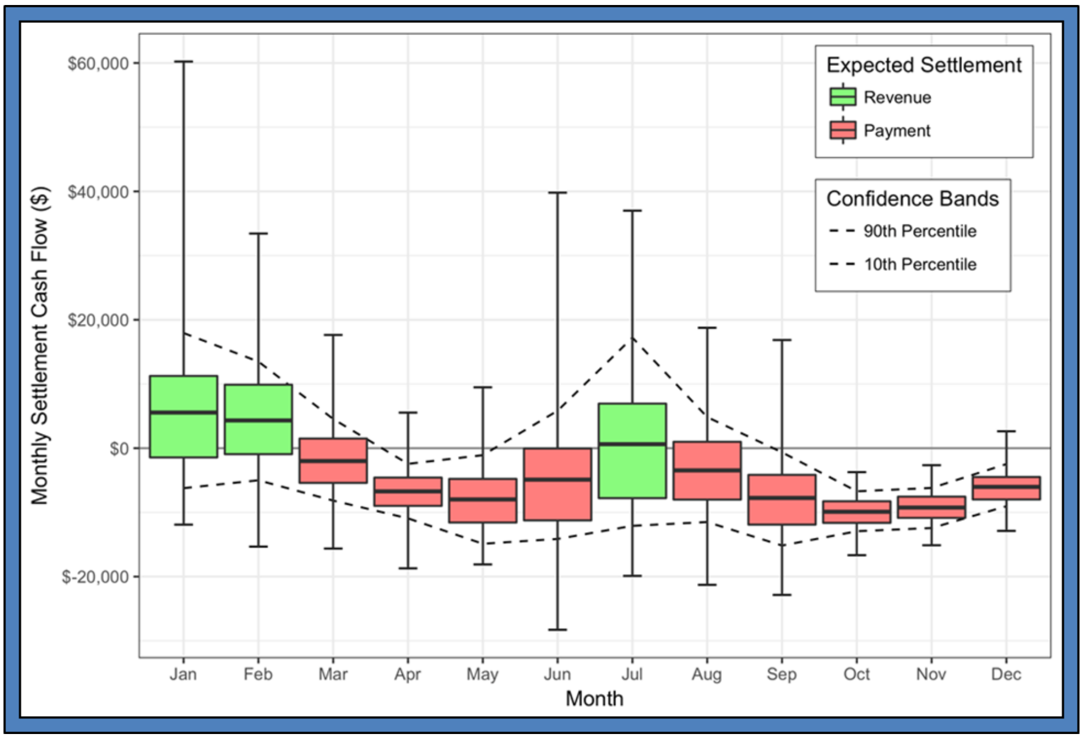

## Computing Monthly Settlement Amounts and Understanding Risk

Aligning the Monte Carlo simulations of hourly renewable generation and hourly real-time electricity spot prices by simulation path and hour, we compute the hourly simulated value of electricity generated over the PPA horizon. For each simulation path, we sum the hourly generation in each month to compute the total monthly generation (TMG) in MWh, and we sum the hourly value of electricity (hourly generation in MWh times hourly price in $/MWh) in each month to compute the total monthly value of electricity (TMVE) in dollars. Denoting the contracted PPA price by K, we compute the simulated monthly settlement amount (MSA) for each simulation i and month j according to the following formula:

$$MSA_{i,j} = TMVE_{i,j} - TMG_{i,j} \cdot K.$$

Figure 6 shows box-and-whisker plots for the simulated distributions of MSAs for the solar VPPA case study in the year 2022. The horizontal black bar in each box represents the expected MSA for that month, and the boxes are colored according to whether the MSA is expected to be a revenue or a payment. At a contracted price of $35/MWh, the figure shows that the VPPA is expected to be out of the money, on average, in most months of the year.

**Figure 6**
**Simulated CFD Monthly Settlement Amounts for 2022, Assuming a $35/MWh Contracted PPA Price**




Note: Statistics displayed in the boxplots are consistent with the convention described in the caption of Figure 2.

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As seen in the figure, the seasonal pattern in expected MSAs roughly follows the seasonality of the forward curve: on average, settlement amounts are greatest in the winter and summer and dip lower in the shoulder months. While simulated PPA value is actually driven by the simulated hourly spot electricity prices in each month rather than the forward curves themselves, solar generation tends to be highly coincident with diurnal patterns in hourly spot prices. Generally, both generation and prices are highest in the afternoon and lowest during the nighttime and early morning hours. Hourly price shapes do also play a role in determining PPA value, but the high degree of coincidence between solar generation and price creates alignment between the forward curve and expected PPA settlement amounts. By contrast, wind generation tends to be far less coincident with hourly price shapes, often peaking at night or in the early morning. Were this PPA contracted on a wind resource, hourly alignment between the diurnal wind generation profile and the hourly price shape profile for each month would likely play a larger role in determining expected MSA over the life of the agreement.

Figure 6 does display the influence of hourly price shapes and hourly price variability on the degree of uncertainty around expected MSAs. Seasonal differences in uncertainty around the expected MSA cannot be understood by an analysis of futures prices alone; a meaningful analysis of uncertainty and risk requires a simulation-based approach that captures location-specific trends in hourly prices and generation across a range of time scales. Electricity spot prices for PJM Western Hub tend to be most volatile in the winter and summer due to constraints on the electric transmission system and the natural gas supply system when customer load is highest. As seen in Figure 6, it is these same times of year when uncertainty in the MSA is highest, evidenced by the long whiskers on the boxplots for summer and winter months.

Importantly, in the summer months, high solar generation volumes tend to magnify the up- and down-side risks associated with uncertainty in electricity spot prices. In particular, when market prices are low, high solar generation levels will exacerbate the effect of these low prices on PPA settlement amounts, magnifying the loss the buyer must take. The contribution hourly price uncertainty makes to MSAs is evidenced in Figure 6 by the taller boxes (encompassing the P25-P75 interquartile range) and the longer whiskers (ranging from the minimum to maximum simulated MSAs) in the summer and winter, which is precisely when uncertainty in hourly electricity prices is highest.

One dynamic that is a growing concern to the renewable energy value proposition is that large quantities of renewable generation may actually exert downward pressure on market prices in real-time. We refer to this as renewable penetration risk, and it can be worsened as new renewable resources come online. For instance, high levels of mid-day solar generation in California can reduce the load net of renewables so significantly that market prices actually become negative at times, signaling oversupply of energy. This oversupply dynamic was forecasted by the California Independent System Operator back in 2013 with the iconic “Duck Curve” chart shown in Figure 1. Analogously, renewable generation oversupply occurs frequently in western Texas, where high levels of wind generation can cause congestion. Congestion is an effect in the local transmission system whereby physical constraints prevent generated electricity from reaching the point of customer demand where it is ultimately consumed. Congestion can often result in significantly negative real-time marginal electricity prices.

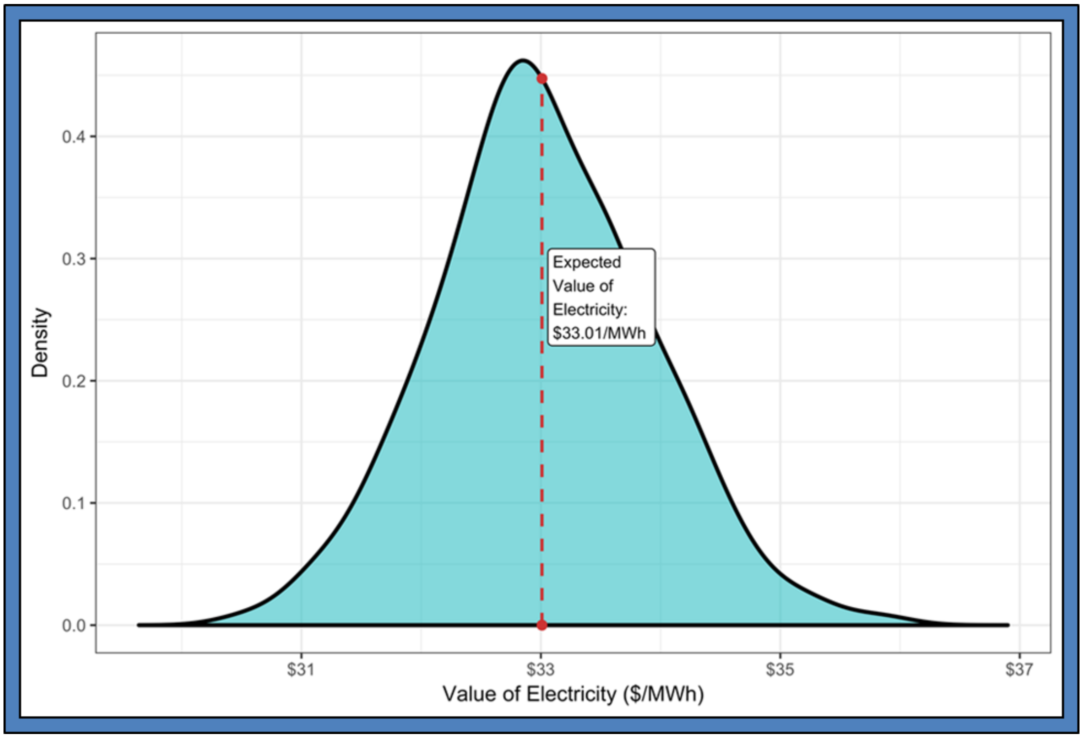
This dynamic whereby intermittency and uncertainty in generation can influence electricity market prices may actually reduce the market value of that generation. As seen in Figure 2, Figure 3, and Figure 4, the variability in renewable generation can be significant across a calendar year, month, day, and hour of the day, and the risk of variability in generation can affect the value of the overall PPA. The amount of generation that fluctuates around the anticipated mean level and the relationship of the fluctuations to the actual price of electricity together comprise the concept of “swing risk”.

Essentially, swing risk is the idea that the overall value of intermittent generation decreases when periods of high generation align with periods of low prices and periods of low generation align with periods of high prices. When this occurs, the resulting production-weighted average value of generation becomes depressed compared to what the forward curve or even the expected hourly shapes of generation and price would suggest. The phenomenon is fundamentally driven by uncertainty around the expected value. Thus, valuing a PPA by focusing on monthly forward prices or expected hourly price and generation shapes misses the swing risk dynamic entirely. To properly assess swing risk, one must use a simulation-based approach that reflects the statistical properties of when swings in both generation and production are likely to occur. In the case study analysis presented here, our simulations of generation and price at the hourly level form the basis on which we build up overall PPA value. Building aggregate PPA value from granular hourly generation and coincident market prices allows our analysis to capture and value the swing risk associated with the particular facility location and PPA settlement hub. It is critical to account for swing risk and potential renewable penetration risk for an accurate determination of PPA fair market value.

**Computing Overall PPA Value**

Finally, by aggregating the simulated real-time value of renewable generation over the entire settlement term, we compute the average value of electricity generated over the life of the PPA. Our simulation-based approach yields not only a point estimate for the average value of electricity, but also a range of possible outcomes based on plausible future generation and market scenarios. Each outcome is associated with a probability of occurrence based on current forward market expectations and historical trends in hourly generation and prices. Figure 7 shows the distribution of simulated average values of electricity produced over the PPA settlement term. Values range from roughly \$30 to \$36/MWh, with an expected value of \$33.01/MWh. Computing the overall value of electricity provides a high-level view of the PPA that reflects current forward market expectations about the future price of electricity, location-specific statistical trends in generation intermittency at the seasonal and hourly level, and the interplay between uncertainty in hourly generation and hourly electricity prices. The expected value of \$33.01/MWh suggests that, given current market expectations, the assumed PPA price of \$35/MWh is likely on the high-end of what the buyer could hope to recover over the life of the contract.

**Figure 7**
**Simulated Value of Electricity Generated Over the Full VPPA Settlement Term**




It is important to note that this distribution of value reflects forward market expectations as of January 12, 2018, the date when the futures contract quotes were obtained. As market conditions evolve, forward curves can move significantly, which in turn changes the expected valuation of any long-term PPA contract. Because the seasonal shape of the forward curve may change in addition to the absolute price level, the effect of forward market shifts on PPA value is highly nonlinear. The best way to track value over time is to periodically perform an analysis like that presented in this case study, based on updated forward market quotes as they become available. Such an analysis effectively serves as a "mark-to-market" process for the PPA and can be of great help to provide early warning signs when market conditions become adverse to previously contracted PPAs. Periodic tracking of PPA value, even after the contract is signed, can reveal changes in value over time and help to identify targeted active management strategies to mitigate risk and safeguard value into the future. Such risk-mitigation strategies are the subject of the second article in this two-part series, to be published in the Winter 2018 edition of the *GCARD*.

## Conclusions

Renewable PPAs can be excellent vehicles for making progress toward corporate sustainability mandates, offsetting carbon emissions, and enabling claims of additionality. However, they are complex long-term financial contracts and should be treated as such within any buyer's broader business portfolio. In this first article of a two-part series on renewable PPA analytics, we illustrated how nuanced interactions between intermittent generation and electricity market prices can significantly impact PPA value. Without proper value tracking and active management, adverse market moves can erode PPA value over time and potentially require the buyer to make settlement payments each month to cover losses on the contract.

Additionally, we discussed how renewable penetration risk, production swing risk, and general market price volatility all present challenges to PPA buyers. A strategy that monitors PPA value by periodically performing a "mark-to-market" valuation of the agreement as forward prices evolve can help provide early warning signs of value erosion. Furthermore, such a periodic assessment can identify key contract-specific risks and inform targeted risk-mitigation strategies that help lock in the value envisioned at the time of contract signing.

In the second article of the series, we will elaborate on the mechanics of such risk-mitigation strategies. As a concrete example, we will build on the case study above, presenting specific strategies to protect PPA value amid volatile and ever-changing energy markets.

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## Endnotes

1 In theory, the VPPA structure can accommodate other forms of generation as well, though wind and solar are by far the most prevalent.

2 At the time this article was published, the real-time market cap for the Electric Reliability Council of Texas (ERCOT) was $9000 per MWh. Locational marginal prices for electricity realized this cap on two separate real-time intervals in January of 2018 during a period of exceptionally cold weather.

3 Negative marginal prices for electricity are indications that the grid is oversupplied. Such negative pricing can be quite common in areas with high renewable penetration. For instance, negative prices are common in western Texas during windy conditions, when the large amount of local wind generation can oversupply the comparatively small electricity demand in the region.

4 Unit-contingent contracting means the buyer agrees to take the energy as-produced from the facility. Such contracts may or may not include monthly or annual production guarantees.

5 Image credit: https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

6 https://en.wikipedia.org/wiki/Nesquehoning,_Pennsylvania.

7 Historical solar radiation data is publicly available from the National Solar Radiation Database. See https://nsrdb.nrel.gov/ for details.

8 See https://sam.nrel.gov/ for details.

9 The assumption that future renewable generation from the facility will reflect similar statistical attributes to historical generation explicitly ignores potential long-term climate trends. In theory, significant change in average rainfall, average temperature, or other weather-related variables at the monthly level could significantly affect renewable facility generation. However, such climate trends are extremely difficult to forecast accurately, and any such treatment was considered outside the scope of the present analysis.

10 On- and off-peak period definitions vary by region. For products that deliver energy within the PJM regional transmission organization, on-peak hours are defined to be Monday through Friday from hour-ending 0800 through hour-ending 2300 eastern prevailing time, with all other hours defined to be off-peak.

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Dr. Brock Mosovsky is Co-Founder and Director of Operations and Analytics at cQuant.io, a leading software-as-a-service provider of energy-focused advanced quantitative analytics. He has more than ten years of analytical modeling experience with a focus on risk management, financial engineering, and model validation for the energy industry. Dr. Mosovsky has worked with the country's largest electric utilities and independent power producers to help improve operational and budget certainty amid volatile financial energy markets and has validated financial models for more than 100 gigawatts of nameplate generation capacity. He holds a Ph.D. in Applied Mathematics from the University of Colorado, Boulder, a B.S./M.A. in Mathematics from Villanova University, and was awarded a U.S. Fulbright Scholarship for study in the Netherlands.

**LANCE TITUS**
**Managing Director, Uniper Global Commodities**

Mr. Lance Titus currently serves as Managing Director at Uniper Global Commodities. He has over twenty years of commodities trading, structuring and risk management experience. He has held senior leadership roles from Wall Street to the energy industry, working for an investment bank as well as for leading utilities, unregulated entities and merchant energy firms. He has transacted in over $15 Billion in trading and originated structured transactions in the energy and environmental commodity markets with a sector focus in electricity, natural gas, renewables, carbon and emissions. Mr. Titus has been a featured panelist at Bloomberg's "The Future of Energy Summit" in New York, and also as a lecturer for the course, "Foundations of Commodities," at the University of Colorado Denver.

Mr. Titus holds an M.B.A. from the Daniels College of Business at the University of Denver and a B.S. in Finance and Marketing from Clarion University. He serves on the Advisory Board of cQuant.io and is a member of the J.P. Morgan Center for Commodities' Research Council as well as its Advisory Council. In addition, he serves as a member of the *Global Commodities Applied Research Digest*'s Editorial Advisory Board.