Growth of US merchant solar primed to accelerate in near term

Merchant solar | In the US and a number of other major solar markets, merchant solar projects are emerging to fill the gap left by declining subsidies. Jay Bartlett of Resources for the Future looks at the risks and opportunities for merchant PV as it finds its feet

Credit: First Solar

First Solar's Barilla plant was one of the first large merchant PV projects

In the United States, solar installations are expected to surge over the next five years, and particularly so for utility-scale projects. The primary driver of this growth is the stepwise decline of the investment tax credit (ITC) from the current level of 30% to a permanent 10% subsidy. Although the first reduction occurs at the end of this year (to 26%), ITC eligibility is based on the start of construction, so long as projects are placed in service by the end of 2023. With the generous incentive available for this period, merchant solar projects—those that are neither owned by a utility or customer nor with a long-term contract for their power—are an appealing option for new solar capacity in the US.

Tax credit deadline spurs rising installations

Figure 1 shows the expected rise in US utility-scale solar installations, from less than 5GW (AC) in 2018 to over 11GW (AC) in 2023, with a steep decline immediately thereafter. To some extent, this pattern has occurred previously. The ITC had been anticipated to decrease after 2016 (although it was extended), which caused a jump in 2016 installations and a reduction in subsequent years' installations as solar projects were pulled forward to meet the scheduled deadline. However, there is a significant difference between solar projects completed in 2016 and those expected over the next five years. Whereas 56% of all 2016 solar installations (utility, commercial and residential projects combined) were used to meet state Renewable Portfolio Standards (RPS), the percentage fell to 38% in 2017 as solar and wind power generation outpaced RPS requirements [1]. Although certain states have increased their RPS commitments over the past year, a large majority of near-term solar capacity will be likely built without RPS support.

Utility contracts have been prevailing structure

Despite the reduced demand to meet RPS mandates, contracts with utilities remain the most common structure for large solar projects. From Figure 2, utility contracts accounted for 85% and 65% of utility-scale solar capacity added in 2016 and 2017, respectively. Not all of these utilities have mandates for solar or renewable power—they may be in states without an RPS or may have already exceeded their RPS requirements. Utility contracts are also known as physical power purchase

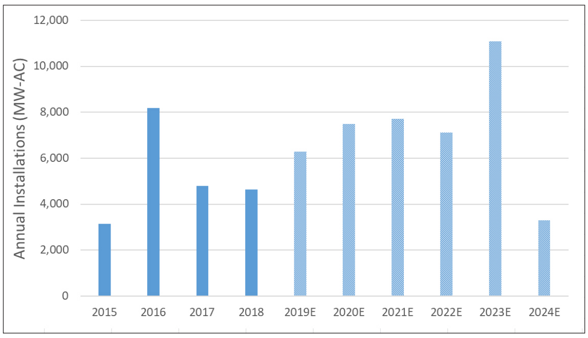

Figure 1. Historical and projected US installations of utility-scale solar. Data for 2015-2022 from [2] Feldman and Margolis 2019, derated by 25% to convert from DC to AC. Data for 2023 and 2024 from [3]

agreements (physical PPAs), so-named because they involve a physical transfer of electricity. Another option for utilities to procure solar power is to own the project themselves, but ownership may or be less advantageous than a physical PPA (due to treatment of the ITC for utilities) and may not be permitted in deregulated markets.

Among the other structural options for megawatt-scale solar, customer ownership and virtual net metering account for minimal capacity. Community solar is a small but growing segment, providing the benefits of rooftop solar for customers in multi-unit housing or without suitable roof space. The final two categories, merchant and customer contracts, together represent the merchant structures for solar. Merchant solar represented 7% and 16% of utility-scale solar installations in 2016 and 2017, predominantly consisting of solar projects that have hedge contracts with large corporations. While the rise in merchant capacity in 2017 is meaningful, merchant solar trails merchant wind by a large margin; nearly half of wind capacity installed in 2017 was on a merchant basis [4]. Moreover, merchant solar in the US has largely been limited to a single structure, a synthetic PPA, whereas merchant wind projects have been completed using a range of structures.

Conditions supporting merchant solar

Despite the comparative immaturity of merchant solar, there are several reasons to believe that the segment will grow substantially in the coming years. As discussed earlier, solar projects will be able to claim the full 30% ITC as long as they start construction by the end of this year and are placed in service before 2024. The 30% ITC was extended in 2015, so developers have had a relatively long time for project planning. Additionally, wind project developers, financiers, and hedging counterparties have completed merchant deals since the early 2000s. While wind and solar have different operational and financial characteristics, the number of successful merchant wind projects and years of experience have likely made market participants more comfortable with the prospect of merchant solar.

Recent trends and developments also favour merchant solar. Historically, wind had a cost advantage over solar, but with the cost of solar power declining by nearly 90% since 2009, average unsubsidised wind and solar costs are now equal [6]. Although recent tariffs on most imported solar cells and modules have raised US module prices above global prices, current US module prices are still lower than ever before. Wind had also benefitted from a more generous incentive than solar, receiving a production tax credit (PTC) of US$23/MWh over 10 years. However, the PTC began phasing out for wind projects starting construction in 2017, and it will expire completely for projects that start construction next year. Similar to the ITC, wind developers have four years from commencing construction to placing projects in service for PTC eligibility, so financiers and hedge providers may turn their attention to merchant solar as the current surge of wind projects subsides.

In considering merchant solar, it is useful first to review the characteristics of a physical PPA, which highlight the contrasting elements of merchant projects. Under a physical PPA, the project receives a fixed price from the utility off-taker for each megawatt-hour of electricity it produces. The utility offtaker typically purchases the electricity at the project's node (where it interconnects to the grid) and assumes responsibility for transmission to where the power is needed. Further minimising risk to the project, physical PPAs have historically been of long duration (often 20 or more years), and utilities generally pose a low risk of default on their contracts. For the project, the low risk comes at a cost—the generation-weighted average levelized PPA price was just US$41/MWh for PV contracts signed in 2017, down from approximately $130/MWh in 2010 [7].

Risks to merchant solar and international experience

The appeal of merchant solar is thus the possibility of obtaining higher prices by selling into a wholesale electricity market. However, the price risks of doing so are substantial. First, regional wholesale power prices fluctuate, and they may decline significantly during the life of the project. Second, merchant projects receive the wholesale power price at the project's node rather than at the regional trading hub. Depending on congestion in the transmission grid, nodal prices may be considerably less than hub prices, causing merchant plants to lose value on their generation. The earliest large merchant solar plant in the US presents a cautionary tale of price risks. First Solar installed the 18MW (AC) Barilla Solar Project in Texas in 2014 on a merchant basis; it wrote down the value of the project in 2017 due to lower wholesale electricity prices.

Experience outside the US also illustrates the risks inherent in merchant solar. With an exceptional solar resource and robust power demand from mining operations, northern Chile was the first market to host a sizable capacity of merchant solar plants. As of May 2018, Chile accounted for 11 of the largest 15 merchant solar plants worldwide [8]. However, the boom of solar projects constructed between 2013 and 2016, combined with constraints in the national transmission grid, depressed midday electricity prices in northern Chile. As a result, development of merchant solar in Chile stalled in 2017. More recently, Australia has rapidly emerged as a large market for merchant solar, with developers seeking better returns than would be possible given the depressed PPA prices. As of mid-2019, there are an estimated 12 fully merchant projects under development or construction in Australia [9], including such large plants as the 132MW (DC) Merredin, 130MW (DC) Aramara, and the 128MW (DC) Cunderdin solar projects. The simultaneous development of numerous solar projects, including merchant as well as contracted plants, will likely lead to price erosion and transmission bottlenecks. Due to grid congestion, the Australian Energy Market Operator has already cut the percentage of solar output that may receive revenue.

Project finance compels hedging

A critical factor affecting the choice between a physical PPA and a merchant structure is the financing of the project. In the US, utility-scale solar projects are typically financed with three forms of capital: sponsor equity, tax equity and debt. Sponsor equity is often contributed by the project developer, and while it carries the greatest tolerance for risk, it

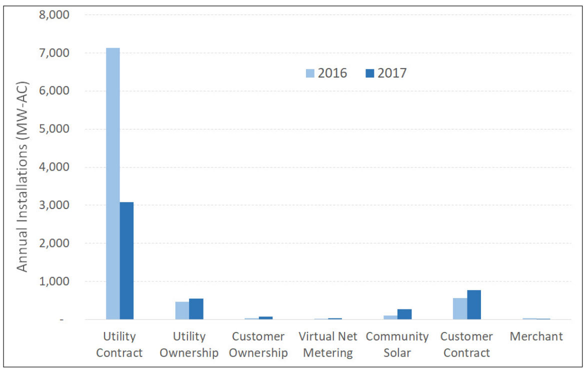

Figure 2. Annual US utility-scale solar installations by sales structure [5]. Solar installations with customer contracts are mostly projects with synthetic power purchase agreements. Data include installations of 1MW (AC) or greater

also represents a small proportion of the total funding, around 25% [10]. Tax equity, providing roughly 35% of total capital, is designed to optimally utilise the tax benefits of the project, including the ITC, accelerated depreciation and interest deductions. Finally, debt supplies about 40% of the financing, and its low cost requires very low risk to the interest and principal payments it receives. The cost and availability of the project's financing is thus dependent on the structure of its electricity sales. Given the price risks of wholesale power, it would be challenging for a merchant solar project to secure tax equity financing, and even more challenging to attract a lender. Consequently, to obtain both low-cost project financing and a greater expected return than with a physical PPA, the project developer must hedge some of its merchant revenue risk.

Hedging options

Figure 3 illustrates the three prevailing hedging structures for merchant wind projects, all of which are now used by merchant solar projects either in operation or under development. A synthetic PPA (also referred to as a virtual PPA or a corporate PPA) is the only type of hedge already in use among operational US solar projects, likely so because it approximates the features of a physical PPA. Similar to a physical PPA, the project receives a fixed price per MWh of energy it generates. However, the arrangement is solely a financial one—electricity produced by the project is sold into the wholesale market. The project receives the floating price from the wholesale market and pays the floating price to the hedging counterparty, a non-utility corporation. The primary financial difference between a synthetic and physical PPA is if the synthetic PPA settles at a trading hub rather than at the project's node. A hub-settled synthetic PPA leaves the project with so-called basis risk, the difference between the nodal price it receives and the hub price it must pay. If there is congestion in the grid, this price difference may be significant.

Contract or Hedging Structure	Quantity Risks			Price Risks	
	Operational & Curtailment	Solar Irradiance	Contracted Volume and Shape	Electricity Hub Price	Basis (Node vs. Hub Price)
Physical PPA (Node)	Part	Part	None	None	None
Synthetic PPA (Hub)	Part	Part	None	None	Full
Bank Hedge (Hub)	Full	Full	Full	None	Full
Proxy Revenue Swap (Hub)	Full	None	None	None	Full
Unhedged Merchant	Part	Part	None	Full	Full

Table 1: Project risk exposures under different contract and hedging structures

The second structure is a bank hedge, which has been utilised by US wind projects for over a decade. While there had been interest in solar bank hedges for several years, only in the past year had solar projects been able to secure these hedges. One challenge with a bank hedge is its transaction cost, which requires greater project size to be sensible. Two solar projects currently in development with bank hedges, the Misae and Holstein plants, are both 200MW (AC) or greater, which is common for wind projects but particularly large for utility-scale solar (only three US solar projects over 100MW were installed in 2017). A bank hedge is also riskier for the project (compared to a synthetic PPA) since it entails a fixed quantity of electricity rather than the variable quantity that the project generates. As listed in Table 1, the structure of a bank hedge exposes the project to quantity risks beyond those that exist in a physical PPA. Quantity risks include the potential for underperformance and curtailment, lower-than-expected solar irradiance, and a mismatch between the timing of contracted volume and actual generation (though this is a lesser concern for solar than for wind). Since all bank hedges settle at trading hubs, basis risk is also a concern for projects using this structure.

Thirdly, the proxy revenue swap is a recently developed hedge, first used by a wind project in 2016. Rather than hedging only against price risk, the proxy revenue swap also insures against weather risk. The project pays the counterparty a percentage of "proxy revenue", equal to the amount the project would earn based on actual solar irradiance levels and hub prices. In return, the counterparty pays the project a fixed annual sum. The project thus fully bears operational and curtailment risk, as well as basis risk, but the project is not liable for lower-than-expected solar irradiance. Proxy revenue swaps require a sophisticated weather risk investor, such as an insurance company, and are uncommon even for wind plants—only four projects have been completed to date. While no US solar project has yet to announce this structure, two Australian projects with proxy revenue swaps, the 95MW (DC) Susan River and 75MW (DC) Childers solar farms, are scheduled for completion this year.

Besides these three hedges, another strategy is to structure the project with partially contracted revenues and partially merchant revenues. The split between the physical PPA and merchant portions can be based on quantity, time, or both. For instance, the 250MW (AC) Phoebe solar project in Texas has a 12-year PPA for 89% of the power. Therefore, the project has 11% merchant exposure for the first 12 years and 100% merchant exposure thereafter. With an approximately 30-year expected life for utility-scale solar, a "merchant tail" after the physical PPA ends has generally been a component of solar projects. The recent change is that potential PPA durations have shortened dramatically (to as brief as seven years), so the merchant tail now accounts for a sizeable proportion of project value. In choosing the split between physical PPA and merchant revenues, project developers may contract for sufficient revenue to satisfy their risk-averse lenders and seek merchant upside for the remainder.

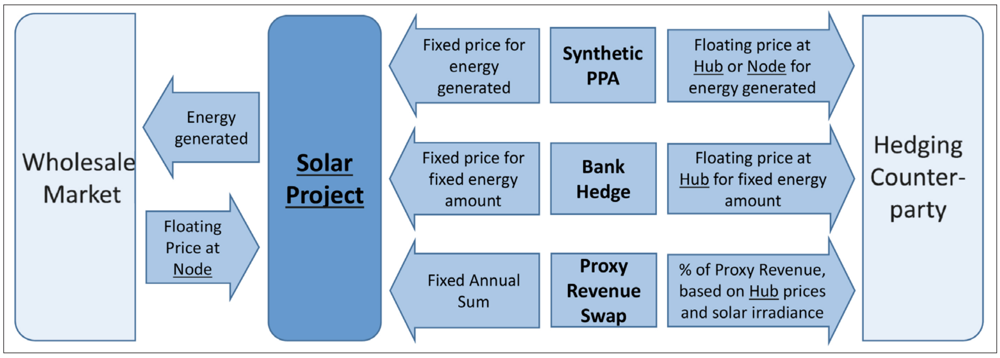

Figure 3. Financial flows from the three hedge structures for merchant solar

Future developments for merchant solar

In the near term, the most significant event for solar will be the reduction of the ITC to 10% for projects installed after 2023. Unless the ITC is extended at a higher level, the percentage of project value coming from subsidies will decline, which will elevate the importance of electricity sales to project financing. This shift will likely lead to less risky revenue structures, either a greater proportion of contracted revenue or the use of hedges, such as synthetic PPAs and proxy revenue swaps, that entail less risk.

Beyond the reduction in subsidies, merchant solar will be challenged by the drop in midday wholesale power prices as the amount of solar generation increases. In such leading markets as California, the erosion in solar prices is already substantial. From 2012 to 2017, solar generation-weighted wholesale power prices fell by 34%, and prices declined further in the first half of 2018 [7]. This price dynamic presents formidable downside and uncertainty to merchant solar projects and hedging counterparties, given the 10- to 12-year duration of many hedges and 30-year duration of solar plants. Battery storage can mitigate this price risk, and US solar PPAs have increasingly included storage, with 16 signed contracts in 2018 versus just four in 2017. Considering the decline in battery prices and rising risk of midday power price erosion, future merchant solar projects may decide to do the same.

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