What to Expect from Energy Markets in 2019

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Introduction

For businesses with high energy spend, activity in the energy markets could have significant downstream effects on the bottom line. However, few businesses have the resources or expertise to monitor the complex and constantly evolving energy world to understand which developments will affect them. Some of the issues that attract mainstream headlines may have no impact on their energy spend, while others that fly under the radar could affect their budget directly.

As we move into 2019, it is critical for large energy users to understand not only how emerging developments in the energy markets might affect them, but also what they can do in response.

As experts supporting more than $8 billion in annual energy spend for our customers, our Energy Intelligence team wrote this report to provide clarity on the road ahead and help energy consumers understand some of the challenges and opportunities in 2019 and beyond.

Section I: Natural Gas

New natural gas infrastructure is having an impact in markets across the US, while production has rewritten the record books for several years consecutively. Even with the record production, however, natural gas storage levels continue to struggle to keep up with rising demand, which is driven by weather and consumption for power burn. Natural gas prices beyond winter 2019 and into 2020 remain low but are at risk for a sudden spike if winter weather materializes later in the season. New sources of demand will help place a price floor on the market if volatile weather patterns emerge later in the winter and the summer.

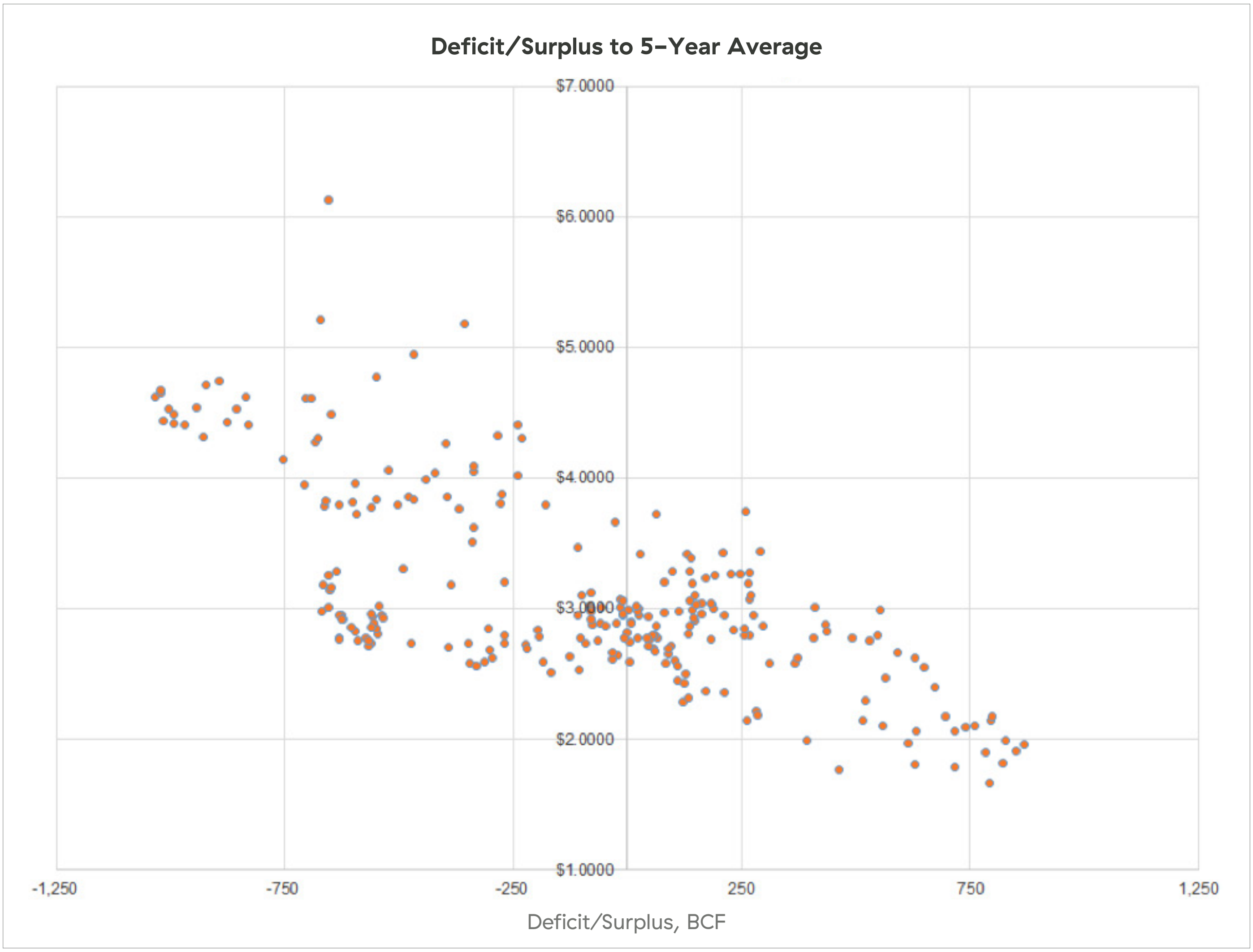
This section dives into the factors that will affect natural gas supply, demand, and pricing in 2019 and beyond.

Natural Gas Demand Forecast

Short-Term Weather Impacts

The continued connection between weather and short-term prices has created significant volatility in short-term NYMEX Henry Hub prices thus far in winter 2018/19.

Fundamentally, natural gas entered November 2018 with the lowest storage level since 2004, at 3,208 Bcf, despite gas production setting new daily records for most of the year. The gas storage deficit to the five-year average ranged from 192 Bcf in early 2018 to 638 Bcf in mid-November, according to data from the US Energy Information Administration (EIA). For the first 10 months of 2018, all NYMEX futures held below \$3.00/MMBtu. However, prices rallied to over \$4.50 in the



winter 2018–2019 NYMEX Henry Hub futures contracts once the winter season began. Since that time, the actual temperatures and forecasts have remained above normal. The warm winter is crippling demand for natural gas, and near-term forward NYMEX prices are back below $3.00/MMBtu. The risk for a return to colder-than-normal weather later in January or early February remains a real possibility.

Customers with NYMEX exposure for winter 2019 may want to consider mitigating that risk below $3.00/MMBtu. April–October 2019 NYMEX prices have a real chance to retest the Summer 2018 low prices of around $2.55/MMBtu. Short-term prices are likely to remain volatile throughout 2019 due to the continued historical growth for both gas supply and demand.

Power Burn

Natural gas-fired power generation in the US has been growing for the past decade, and that trend looks likely to continue for the foreseeable future. The demand for power is growing quickly, and as cheap natural gas continues to dominate the market share of the new and existing load, expensive resources such as coal and nuclear are gradually leading to retirement.

According to an EIA report, natural gas accounted for 36% of electricity generation in 2018 and, with predictions anticipating the addition of 8.1 GW of new gas-fired capacity this year, power burn demand will continue to put upward pressure on natural gas prices through 2019.

Pipeline Exports

Demand for both pipeline and liquefied natural gas (LNG) exports to Mexico continue to grow as natural gas generation becomes the replacement of choice for less efficient generation sources in the country. Mexican demand will continue to provide price support in the southern region, and will grow as more infrastructure comes online.

As Mexico's deregulated energy markets mature, growing pains associated with the lagging infrastructure are weighing on electricity markets. Generators are being forced to switch fuels due to limitations on natural gas pipelines to meet grid demands, and Mexico is becoming more reliant on LNG exports.

US exports are currently falling short of their potential, with 2018 capacity for 13.5 Bcf[1] and actual pipeline exports to Mexico averaging about 4.7[2] Bcf/d . LNG exports into Mexico have increased by more than 38% year-over-year as a result, according to EIA data.

Pipeline delays continue to plague natural gas imports and pricing throughout the country. Some pipelines that announced delays in December 2017 have completely halted construction, and now the average delay is extending beyond a year and a half. These delays will continue to suppress pricing in the southern US, while increasing demand-driven volatility in Mexico. Customers in the region might not see relief until late 2019 or 2020.

LNG Exports

Liquefaction and export capacity growth will pick up in 2019, and as more facilities commence commercial operations, demand for natural gas will increase along with it. Low natural gas prices continue to help maintain competition with alternative fuels across most of the world, and continued growth of international demand will sustain upward pressure on US natural gas prices.

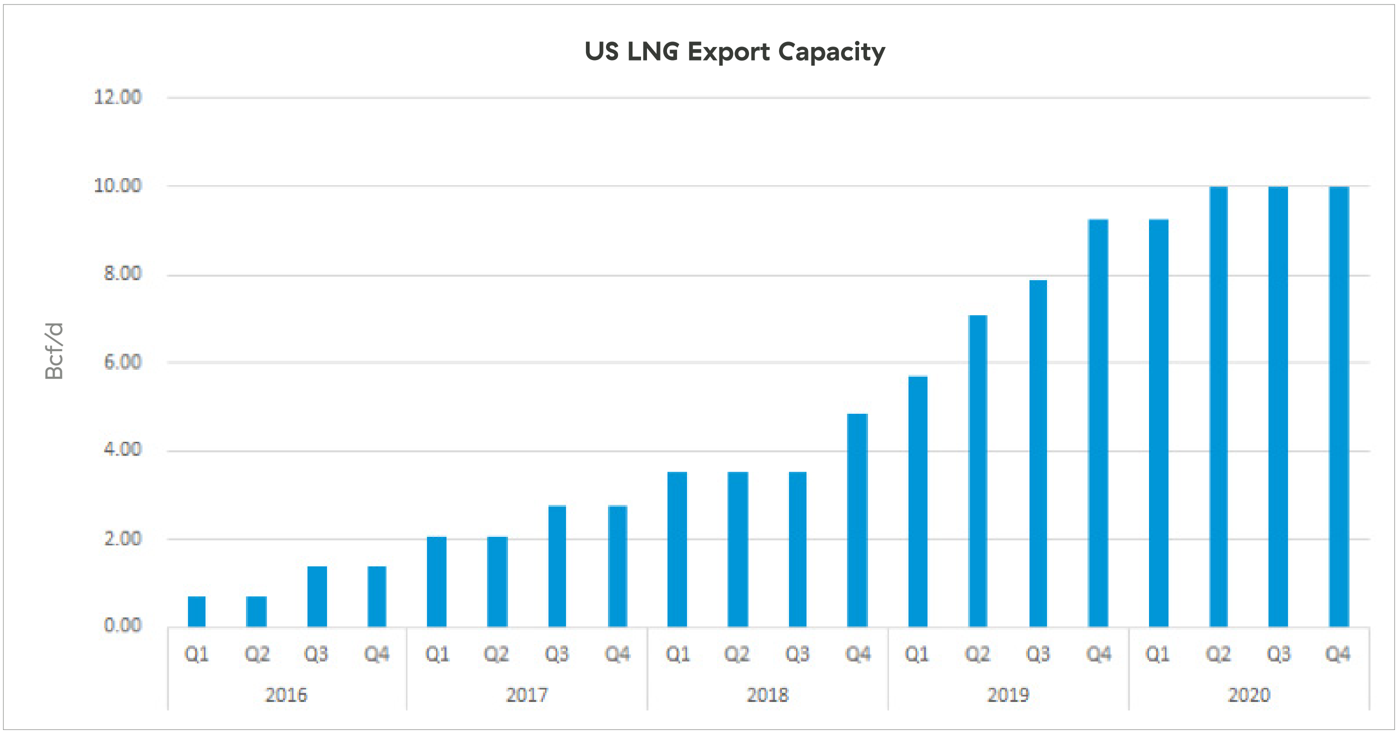
In 2017, LNG exports saw more than a 400% increase in volume over exports reported in 2016. According to EIA data available through October 2018, exports have grown nearly 200%, from 464.6 Bcf in 2017 to 852.7 Bcf in 2018. The increase is directly attributable to the new capacity added at the Sabine Pass liquefaction facility in Louisiana and Cove Point liquefaction facility in Maryland in 2018. Exports for the calendar year are poised to top approximately 3 Bcf/d, a 50% increase over 2017. New capacity is expected to go in service as early as Q1 and nearly double by the end of 2019. Current planned capacity should top 10 Bcf by the end of 2020, as shown in the graph below.

Natural Gas Supply Forecast

The primary influences on natural gas supply are production levels, storage levels, and pipeline capacity. While growing production and pipeline capacity in 2019 should have a dampening effect on natural gas prices, the low levels of natural gas currently in storage leave the market vulnerable to sudden price spikes.

Natural Gas Production

US natural gas production broke records in 2018, reaching an all-time high in both total output and year-over-year growth. Based on the EIA's December Short-Term Outlook, dry natural gas production is forecast to average 83.3 Bcf/d in 2018—representing growth of 8.5 Bcf/d, or 11%, from 2017 levels. For comparison, the previous record for year-over-year growth was 4.6 Bcf/d in 2014. The growth in production largely stems from improved drilling efficiency, increased pipeline takeaway capacity in the northeast, and higher oil prices that led to an increase in associated gas production.



Looking forward, we expect production to continue to break records in 2019, as the EIA is forecasting output to average 90 Bcf/d—a year-over-year increase of 6.7 Bcf/d, or 8%.

Pipeline Development

Production is poised to ratchet higher in 2019, led by new pipeline developments in the Appalachian basin. In recent years, the growth of natural gas output in the Marcellus and Utica shale basins in Pennsylvania, Ohio, and West Virginia has been constrained by the lack of available takeaway pipeline capacity to transport the gas to new markets where it can fetch higher prices. We expect late 2018 and 2019 to be remembered as the turning point for producers, when pipeline capacity out of the region finally reached sufficient levels to trim regional discounts to Henry Hub and enable previously untapped natural gas reservoirs to be brought online.

In the fourth quarter of 2018, four major interstate projects were completed: Energy Transfer's Rover Phase II, Williams' Atlantic Sunrise, Spectra's NEXUS Gas Transmission pipeline, and Transcanada's Mountaineer Xpress. Together, these projects added a combined 7 Bcf/d of incremental takeaway capacity to new gas markets in the Midwest, Southeast, Gulf Coast, and eastern Canada. Including these projects, nearly 12 Bcf/d of total pipeline capacity was placed into service from the Northeast during 2018, with more than 80% completed in the last quarter, according to company reports.

If all planned projects come online by their scheduled in-service dates, the Appalachian basin will add nearly 10 Bcf/d of additional takeaway capacity in 2019. Notable projects include the Mountain Valley, PennEast, Supply Header, and Atlantic Coast pipelines—all of which are scheduled to start up in the fourth quarter of 2019. While regulatory and logistical risks remain in bringing this additional infrastructure online, there appears to be ample spare capacity in 2019 to allow producers to ramp up output and ship excess gas to new markets.

As low-cost shale gas leaves the region, customers in Dominion South and North should expect continued upward pressure on basis pricing. Meanwhile, customers in the Midwest, Mid-Atlantic, and Southeast regions stand to benefit the most from the pipeline buildout.

Natural Gas Storage

Natural gas storage levels are yet another crucial pricing determinant. During low demand periods, more natural gas is produced than consumed, and the excess is injected into storage in reserves around the country. The typical injection season in the US runs from April 1 through October 31. During the typical withdrawal season—November 1 to March 31—demand tends to increase at a faster rate than production can accommodate due to increased heating needs.

Despite record production in 2018, US natural gas storage has remained persistently low compared to historic levels. Increased natural gas demand resulting from bullish weather, expanded exports, and a healthier economy largely kept pace with production growth during 2018, and thereby limited the size of natural gas injections over the course of the year. Specifically, starting in late 2017, inventories dipped below the five-year average, and have remained at a deficit since then. Following one of the hottest summers on record and a cold start to winter, storage inventories finished the injection season at 3.2 Tcf—their lowest level since 2005. Heading into 2019, natural gas in storage was about 13% lower than it was at the beginning of 2018, and 15% lower than the five-year average.

While the storage deficit is expected to shrink sharply this spring as new production comes online, prices in 2019 will be largely determined by how weather unfolds this winter. Given the lower storage buffer, if this winter turns out to be colder than usual, we could see prices for the balance of 2019 rebound. Conversely, if weather patterns get warmer, we could see prices hit fresh two-year lows below $2.50/MMBtu.

Section II: Regulatory Outlook

As the energy industry continues to adapt to the evolution of the US power generation mix, new regulations are emerging as a result. In some markets, customers may gain access to more options for energy supply, while others may see costs rise as a result of emerging regulations.

This section evaluates the impact of specific regulatory developments in key markets across the US.

West Coast

California Renewable Portfolio Standard Overhaul and Direct Access Expansion

New carbon policy goals will help steer wholesale markets in California, but costs are expected to increase in the interim. California remains a leader in the integration of renewable generation into wholesale markets. In September, California Governor Jerry Brown signed into law Senate Bill 100, which increases requirements to meet energy demand with renewables to 50% by 2025, 60% by 2030, and 100% by 2045—making California the second state to commit to 100% carbon-free electricity, behind only Hawaii. While these new regulations seem relatively ambitious, they do allow load serving entities (LSE) to procure up to 25% of compliance obligations with tradable renewable energy credits (TRECS), which will make it easier for utilities and retail suppliers to meet minimum compliance standards.

Another measure that made it past the California legislature was an expansion of the choice market, or Direct Access (DA). Prior to the expansion of DA, 20,000 MWh of commercial and industrial electricity demand could purchase energy from a third-party supplier annually. Senate Bill 237 added 4,000 MW of additional participation in the DA program, increasing load under competitive supply by about 2.5%. The new 24,000 MWh DA cap represents roughly 15.5% of total load and should allow the entry of roughly half of commercial load currently in the DA pipeline. SB 237 also included an option to expand DA even further in 2020. However, the expansion of DA doesn't come without its catches. While customers who participate in DA can significantly reduce energy spend through the competitive supply market, they are also subject to Power Charge Indifference Adjustment (PCIA) charges. These charges, which currently account for roughly 13% of total electricity bills, have been forecasted to increase by the California Public Utilities Commission (CPUC) by 1.68% to 5.24%. Community Choice Aggregators, however, are forecasting increases between 18% and 25%[3].

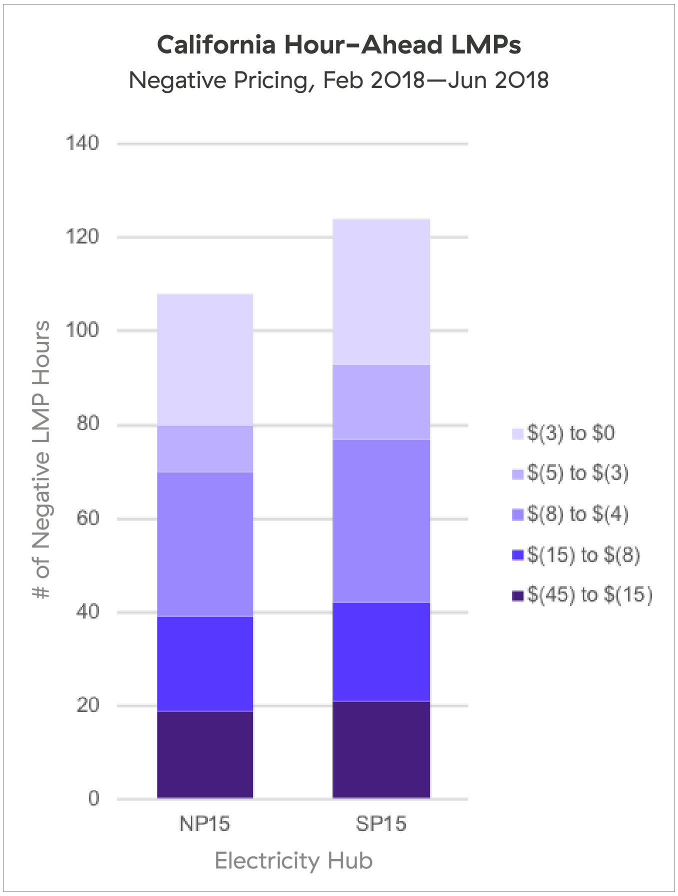
While two major pieces of legislation passed, measures around mandatory renewable procurement failed. Assembly Bill 893 was brought to a vote to fast-track 2,500 MW of solar and wind generation to be procured in 2019, driven largely by the impending expiration of the Production Tax Credit (PTC) and Investment Tax Credit (ITC). While the rejection of Assembly Bill 893 is a minor setback for progress toward California's renewable energy goals in the near term, it does not put the move to 100% clean energy at risk quite yet. The expansion of the Direct Access program could help spur growth of renewables within the California Independent System Operator (CAISO) and Western Interconnection to help meet the state's renewable targets. Customers operating in a de-regulated market will have easier access to renewable power, while generators will be able to pursue more customers seeking carbon-free generation and aggregate customer loads to finance their projects.

Energy Imbalance Market, or RTO—That Is the Question

The Western Energy Imbalance Market (EIM), a real-time trading market in the western United States, was launched in 2014 by the CAISO and Pacificorp to create a system that facilitates serving real-time customer demand at the lowest possible cost. The system also aids in covering the intermittency of renewable generation by balancing the grid.

In addition to the legislation aiming to expand Direct Access and establish the new RPS goals, Assembly Bill 813 proposed expanding California's wholesale market to include more of the Western Interconnection, parts of Canada, and Baja California, Mexico. Supported by state officials and environmental groups, the move was touted to increase savings to consumers and expand California's access to renewable resources; however, it failed to pass in the Assembly. Opponents to AB 813 suggest that establishing a new regional transmission organization would lead to increased costs for consumers. The City of Los Angles voted against AB 813, but will join the EIM by 2020. In its decision, the Los Angeles City Council suggested that a better alternative would be to expand the EIM, as it would enable access to the market without forcing utilities to sacrifice autonomy[4]. While AB 813 failed to pass in last year's session, the measure could live on into 2019.

Another alternative to creating a new RTO would be to expand cross-state participation in a day-ahead EIM. This would encourage renewable generation by expanding commitment options for generation owners. A well-organized and interconnected market creates more efficient pricing by optimizing the delivery of energy across the market. The chart below shows the number of hours Locational Marginal Pricing (LMP) at California North Point and South Point experienced negative pricing. From February 2018 through June 2018, both pricing points experienced over 100 hours where LMPs went negative. Negative prices send signals to generators to reduce or curtail generation due to overproduction—in fact, when renewable energy is curtailed, 60% of the time it's due to excess generation in the local area. For customers, the expansion of the EIM or formation of an RTO could make market prices more stable and potentially spur additional penetration of renewable resources by serving load more efficiently across a larger geographic footprint.



Nevada and Arizona Explore Energy Choice and Higher RPS Targets

Unlike the eastern United States, most of the western energy markets are either regulated or only partially deregulated. In Nevada, energy market deregulation was on the ballot during the midterm elections. Backed by billionaire Sheldon Adelson after his previous efforts to remove the Sands Casino's load from NV Energy's service without paying $24M in fines, Question 3 on the ballot attempted to amend the state constitution to allow energy consumers to choose from competitive suppliers by 2023. Although the ballot measure gained support from other large businesses in the state, including other casino companies and one data center company who have already paid approximately $173M[5] to leave NV Energy's grid, the ballot measure was voted down in November.

While the specific impact of the proposal on energy prices is unclear, deregulation at the wholesale and retail level would have made it easier for Nevada to fulfill its commitment to meet 50% of its energy needs with renewable energy by 2030—a goal which was just established in 2018. As stranded assets fail to compete against the market, newer, cleaner resources could allow renewable penetration to grow organically.

Meanwhile, Nevada's neighbor Arizona has shown momentum toward de-regulating its energy market. While the issue is nothing new for the Arizona Corporate Commission to review, de-regulation now appears to have the support of three of the commission's five board members[6]. Arizona passed initial retail choice legislation in the 1990s with a mandate for utilities to divest assets by 2001, but later suspended the rules due to lack of competition. The issue was raised again in 2013, but later quashed over concerns over grid reliability. The next round of proposals for deregulation is expected to occur later in 2019 and could heat up as the year continues. Only one commissioner who participated in the ruling that rejected de-regulation in 2013 remains on the commission today[7].

Customers should keep an eye on this development and how the rules of a potential choice plan evolve. Details of the plan notwithstanding, the ability to shop from competitive suppliers could deliver significant savings in the long run.

East Coast

PJM Capacity Market Teeters at FERC

In late 2017, the US Department of Energy (DOE) issued a Notice of Proposed Rulemaking (NOPR) aimed at providing financial support for coal and nuclear facilities for grid reliability. As noted in our 2018 report, FERC unanimously rejected the NOPR in early January 2018 on the grounds that the directive was "too vague in description and narrow in solution."

After the dust had settled, PJM released two competing proposals under a whitepaper covering price formation. The first proposal was an extension of the Minimum Offer Price Rule (MOPR-Ex), which sought to change the definition of flexible and inflexible units, redefine LMP pricing, and reduce uplift payments. The second proposal, like the methodology shown in the graph below, was a two-part capacity auction—where the auction would settle as originally designed, but would account for subsidized resources on a separate pass. Both proposals would more than likely represent an increased cost to end-use customers.

PJM's initial proposals were rejected at FERC in late June 2018. This also included a proposal from Calpine to extend the MOPR only to specific resources. FERC confirmed Calpine's initial complaint and found PJM's tariff to be "unjust and unreasonable."[8] FERC acknowledged that subsidized generation has caused suppressive impacts to both the Reliability Pricing Model (RPM) and PJM's competitive capacity construct, as well as the MOPR.

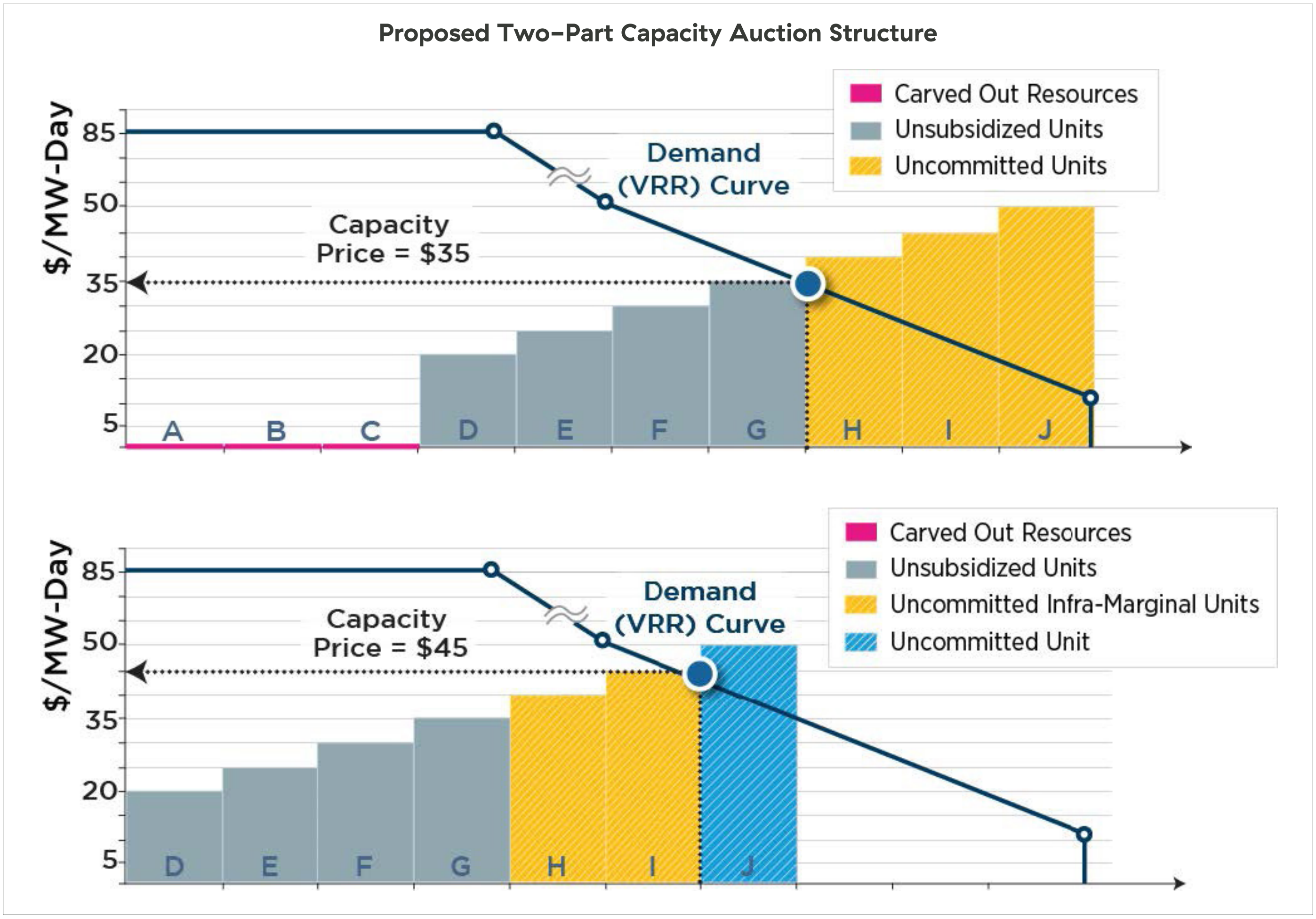


Image Source: PJM Filing to FERC
https://www.pjm.com/-/media/documents/ferc/filings/2018/20181002-capacity-reform-filing-w0172181x8DF47.ashx

Currently, two proposals submitted to FERC offer potential market fixes, both of which include the MOPR changes that would effectively bar out-of-market bids from resources receiving subsidies. The difference in the options lies on the treatment of the Resource Carve-Out (RCO) component on the auction. In the standard RCO, generators that were removed due to the MOPR would be able to establish a capacity commitment without having to submit a bid to the auction. The initial concern is that the standard RCO would fail to fix the artificially low capacity clearing prices, and exacerbate the issue that the market reforms were supposed to fix. PJM's second proposal, RCO-extended, would remove the resources from the pricing model and recalculate the clearing prices by factoring in the demand that the subsidized resources would serve.

With the final tariff still in question, PJM requested a delay in the Base Residual Auction to determine the base capacity prices for the period beginning June 2022 through May 2023. The three-month delay pushes the auction settlement from May to August 2019. The determination of the Variable Resource Requirement was also delayed, from February to May 2019.

Customers should be aware that the downstream effects of these developments will likely drive up costs in the short term, whether through increases in capacity costs or through new subsidies. Like the Capacity Performance rules PJM implemented in 2015 to enhance grid reliability, the new market rules will be more than enough to trigger "Change in Law" provisions in retail electricity contracts. Capacity auction delays could limit the willingness of some suppliers to transact fully fixed rates for the 2022/2023 PJM capacity year. The auction delay could roll into contracting decisions for customers and come at an opportunity cost if market prices go higher.

Nuclear Subsidies Starting To Boil Over

Failing nuclear and coal dominated the news in 2018, and more states are choosing to take matters into their own hands—at a cost to consumers. As profit margins continue to become tighter and major changes to the PJM capacity market loom over the market, the threshold for shuttering generation plants has been reached and 4 GW of nuclear capacity in Ohio and Pennsylvania recently announced retirement.

FirstEnergy Corp declared bankruptcy along with two separate waves of coal and nuclear retirements exceeding 8 GW total (inclusive of the nuclear capacity mentioned above). Along with the bankruptcy, FirstEnergy appealed to the US DOE directly expressing concerns about grid resiliency in future periods under Section 202 (c) of the Federal Power Act, which allows the DOE to require grid operators to negotiate individual cost-based rates with each plant identified. PJM studies, however, revealed no immediate concerns as a result of the retirements.

New York and Illinois were the first two states to implement nuclear subsidy programs. Both states saw court challenges to their Zero Emission Credit (ZEC) programs. In the New York case that was upheld in September, the court found that "FERC allows states to subsidize facilities for environmental or policy reasons," according to a Jurist article[9]. Similarly, in Illinois, the ZEC program was upheld, deferring subsidy oversight to the state. These decisions by the US Court of Appeals will be critical as more states adopt subsidies for generation through new ZEC programs.

In 2018, New Jersey became the fourth state to implement a formal subsidy program, behind New York, Illinois, and Connecticut. Similar to those programs, New Jersey's legislation included revised Renewable Portfolio Standards (RPS) targets along with an implementation of the ZEC subsidy. The revisions implemented also included large jumps in solar generation requirements, offshore wind, and energy storage targets.

While the treatment of subsidies in capacity markets is up to FERC, the possibility of more states and the federal government implementing programs will be a central concern in 2019. Pennsylvania and Ohio both have similar legislation floating around their state legislatures, and more states could follow suit as market fundamentals change.

The introduction of ZEC programs distort true market-clearing prices of capacity and create inefficiencies that suppress capacity prices. PJM's proposed rule changes could have a profound impact on states considering implementing ZEC programs. New York and Illinois are setting legal pre-cedent and are paving the way for this legislation.

Customers should continue to remain diligent on legislation proposed in their respective states, as suppliers often pass the costs resulting from changes in the structure of RPS onto customers. 2019 will see a showdown between FERC, grid operators, and the DOE in how best to protect the future of the grid, and this will come as a cost increase to end users.

Massachusetts Unveils Clean Peak Standard and RPS Changes

Massachusetts continues to move forward with efforts to reduce carbon emissions and champion renewable energy, but those actions come at a cost. The state's electricity rates are already among the highest across in the country, and they are not likely to fall anytime soon. Massachusetts is divided into three separate load zones: West Central Massachusetts (WCMA), Southeast Massachusetts (SEMA), and Northeast Massachusetts (NEMA). The most expensive zone, NEMA, lies around Boston and the surrounding areas. Electricity rates tend to be higher in the northeast due to pipeline capacity constraints on the Algonquin Natural Gas Pipeline. As natural gas generation remains the primary generation type that sets market clearing prices, exposure to a pipeline that can experience basis volatility in the winter ranging between $2.155/Dth to $78.880/Dth requires pricing additional risk into forward prices.

In August 2018, Massachusetts Governor Charlie Baker Signed Bill H.4857 into law. The legislation, "An Act to Advance Clean Energy," included revised RPS targets, implemented energy storage and offshore wind targets, and established the nation's first Clean Peak Standard. RPS costs increased annual growth rates from 1% annually to 2% annually for Class I resources. Suppliers will now be required to purchase 35% of electricity from wind, solar, and small hydro resources by 2030—an increase of 10% from the previous target. The law also increased the energy storage target from 200 MWh to 1,000 MWh by the end of 2025. Authorized offshore wind procurement doubled from 1,600 MW to 3,200 MW. The new law requires the Massachusetts Department of Energy Resources to perform analysis on the value and necessity of offshore wind.

The establishment of the Clean Peak Standard (CPS) represents the first mechanism of its kind. All electricity supply contracts entered into after December 31, 2018 will be required to meet a baseline percentage of kilowatt-hour sales to end-users from clean peaking resources. The resources that qualify not only have to be "clean," but must also deliver energy during a specified peak demand period. These new rules are meant to create incentive for the adoption of energy storage, demand response, and dispatchable solar and battery systems.

Based on current market prices for Class I RECs, customers will more than likely see increases in their bills associated with the increase in the RPS components of their rate. Customers should be wary about the exact costs of the new CPS charges. For 2019, the minimum compliance purchased energy is 0%, so we expect negligible to neutral impacts for the 2019 and 2020 compliance years. The uncertainty can be likened to the Solar REC Carve out compliance costs, which are determined right before the beginning of the compliance year. At the end of the day, rate relief will become more difficult as many of the costs to serve become fixed.

Section III: Hitting Corporate Renewable Goals

In 2018, corporate purchases of renewable energy reached record levels. This year will likely see a similar number of blockbuster purchases from the large corporations aiming to fulfill their public renewable energy commitments, not to mention those that have made new commitments.

Project developers have incentive to pull their projects forward into 2019 and 2020 to take advantage of federal incentives. However, the pipeline for these projects may decrease as the incentives diminish, thereby reducing supply and increasing prices for renewable energy buyers, including corporate off-takers.

In this section, we will review the trends in the renewable market through the lens of the corporate buyer seeking to make renewable purchases.

Growth in Commitments

A 2017 study by Unilever[10], which surveyed over 20,000 people in five different countries (from both developed and emerging economies), revealed that over 1 in 5 (21%) respondents prefer to support brands that clearly convey the sustainability of their products or support sustainability as a part of their corporate social responsibility initiatives. This shift in consumer preference has led many large corporations to establish aggressive targets for adoption of renewable energy or promises to achieve carbon neutrality. As of 2016, 48% of the Fortune 500 had established goals to reduce greenhouse gas emissions from their operations, with more than 20 companies pledging to shift to 100% renewable energy[11]. For instance, Facebook set 2020 as a target for "supporting their operations with 100% renewable energy,"[12] while Google met their 100% target in 2017[13]. Moreover, the number of companies making these commitments has not plateaued. The RE100, a global initiative by the Climate Group through which companies commit to 100% renewable electricity, showed in its 2018 Annual Report that the number of companies making such commitments rose 24% last year[14].

This trend is not limited to consumer-facing companies. Large corporations are passing the pressure to develop strategies to "go green" throughout their supply chains. Netflix's most recent Renewable Energy update[15] provides an interesting example. While Netflix facilities used 40,000 megawatt-hours (MWhs) on their own in 2017, the Amazon Web Services (AWS) data centers on which Netflix relies consumed over two-and-a-half times that amount of electricity in order to run Netflix's operations. For Netflix to meet its sustainability commitments, it will need to account for the impact of critical services like AWS. The ability to align with these goals will become a competitive differentiator for suppliers, which will continue to increase demand for renewable energy.

Corporate purchases are not the only source of rising demand for renewables. Several states increased their commitments through the renewable portfolio standard (RPS) in 2018, including California, Nevada, New Jersey, and Massachusetts, while governors-elect in Illinois, Colorado, New Mexico, and Maine are voicing plans and commitments to renewable energy. In addition, utilities in the Midwest, namely Consumers Energy and NIPSCO[16], are committing to moving away from coal generation and making room for renewable generation, while Xcel Energy became the first US utility to commit to zero-carbon electricity when it announced a 2050[17] goal in late 2018.

How Companies are Achieving their Renewable Goals

In terms of achieving their renewable energy goals, most companies have four basic options:

- On-site behind-the-meter generation
- Purchase of Renewable Energy Credits (RECs)
- Utility "green tariff" or projects sleeved through the utility
- Power Purchase Agreement (PPA)

Most companies do not elect to generate renewable energy for all of their needs on-site, but rather purchase it from renewable energy developers. This route is typically more accessible, but within it has a few different flavors.

Companies can purchase Renewable Energy Credits (RECs) from a solar or wind project. RECs account for the environmental attributes of green power, and can be used to fulfill renewable energy mandates, but they do not include the actual value of the energy itself.

In some regulated territories, customers may have the opportunity to select a green tariff with their utility, which ensures a certain percentage of their generation comes from a renewable resource. Under green tariffs, a utility will enter into an agreement with a renewable project(s) and offer both the power and RECs to residential and commercial customers in the utility's distribution area. In addition, a corporation can negotiate with the utility directly on a specific project(s) and sleeve it through the utility for the corporate entity.

However, the most popular method of renewable energy procurement has been via power purchase agreements (PPAs), either a direct PPA with onsite/adjacent generation or offsite resources through a virtual PPA (vPPA). PPAs allow both the developer/project owner and corporate offtaker to negotiate on a long-term PPA price, volume, and contract terms, and they typically tend to be long-term agreements (10-20 years) for larger volumes (100 MW+). Most PPAs act like a long-term hedge on energy prices for the off-taker, although there is some variability in price.

Demand for MWs

Overall, 2018 marked a year of tremendous growth in corporate purchases of renewable energy from not only companies making commitments but also MWs on the grid. According to the Rocky Mountain Institute, corporate renewable deals added a whopping 6.43 GW of renewable generation in the United States in 2018, which is almost two and a half times the growth from the previous year[18]. Most of these purchases came from the tech community and involved offsite projects that were generally larger than 100 MW. This large leap in capacity and number of purchases is not surprising, with deadlines for many corporate renewable energy commitments coming in the next decade[19]. This partially explains why corporate buyers have adopted the PPA structure so actively. PPAs allow for direct negotiation on large projects that are not restricted to the organization's geographic location, providing access to more projects and potentially better PPA prices with more flexible contract terms.

In our assessment, we expect continued growth in corporate renewable purchases in 2019. The RE100 list alone represents about 29 TWh of energy load globally, which is equivalent to "...the 23rd largest [country] in terms of electricity use, ahead of Egypt and just behind Thailand."[20] Corporate buyers are showing ample demand globally to fuel sustained growth in purchases going forward.

External Factors That Could Restrict Renewable Supply

Just as demand for renewables is escalating, restrictions on supply could exacerbate PPA pricing for corporate customers. While there are many obstacles to adding renewable generation to the grid, we are focusing on a couple of trends that will likely increase the prices of wind and solar generation and potentially restrict supply in the future. First, two key tax benefits, both the Production Tax Credit (PTC) and the Investment Tax Credit (ITC), are being reduced and/or phased out. Secondly, the tariffs on imported solar cells and modules that the Trump Administration implemented through Section 201 in 2018 could further complicate the economics of renewable projects.

The PTC has been around since 1992 and provides an incentive on $/kWh produced pegged to inflation from 1993[21]. The incentive has long been credited with assisting in the boom of wind energy across the United States. Beginning in 2021, however, the PTC will begin to step down by 20% per year. Similarly, the ITC is a tax credit for up to 30% of the project cost. Typically, solar developers use the credit, but it can also be applied to wind projects in lieu of the PTC. The incentive was implemented in 2005, and, like the PTC, has been credited with assisting the solar boom. The ITC steps down to 26% in 2020, 22% in 2021, and for commercial customers 10% permanently in 2022[22]. As a result, there is a backlog of projects seeking to move forward to take advantage of the federal incentives. The phase-outs have been known for the past few years, but it is important to bring up in the context of corporate purchases. Especially in the next year, timing will be key to securing a favorable rate.

On January 22, 2018, the Trump Administration implemented Section 201, which put a 30% tariff on imported solar cells and modules. The tariff is slated to decline by 5% for a four-year period, and increased costs on solar projects due to the tariffs are expected to be $0.12/watt in the first year, $0.10/watt in the second year, $0.07/watt in the third year, and $0.05/watt in the fourth year[23]. Simply put, the tariff will result in increased prices for solar projects.

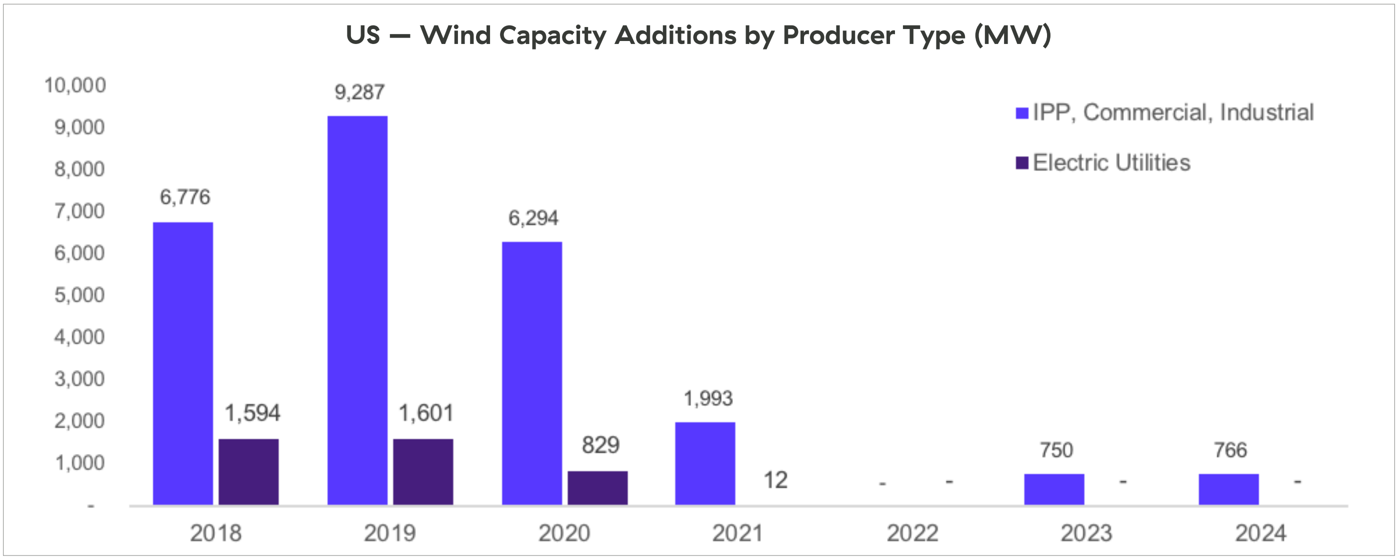
Fortunately, the cost of solar projects continues to decrease due to efficiency gains and technological improvements, while the emergence of state incentives will help offset the impact of the tariff in some markets. However, the tariff creates an added layer of complexity to projecting a renewable project's cost and value. While project developers will see costs for panels decline as the tariff decreases every year, the ITC step down may counteract that decrease.

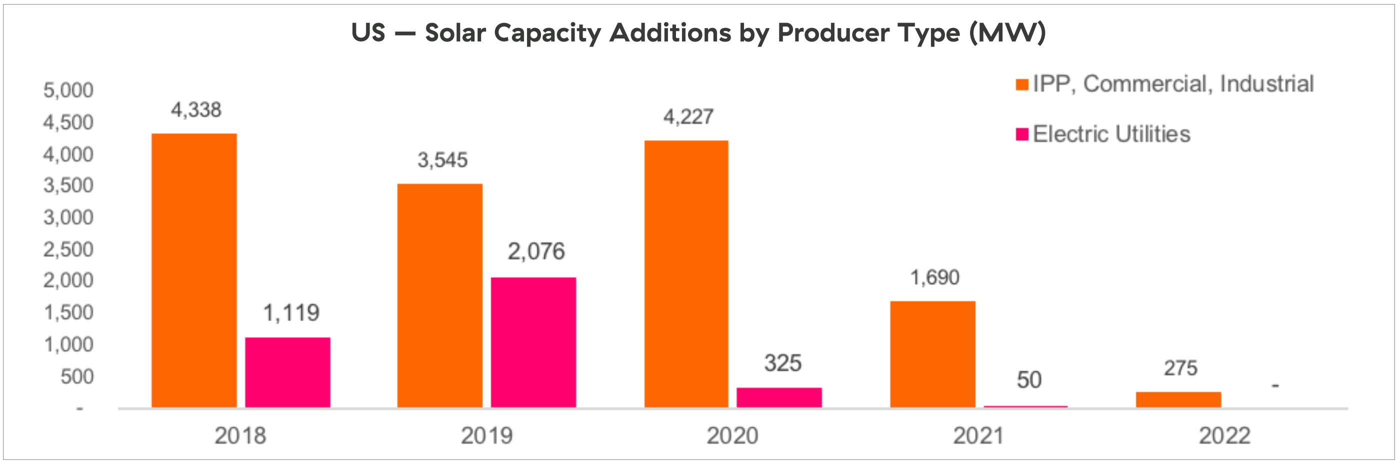
The credit phase-outs and solar tariffs indicate a trend of increased prices for renewables in the future. A poll conducted by the Rocky Mountain Institute indicated that half of responding buyers will speed up procurement for renewables as a result of the phase outs[24].

Pipeline for Renewable Projects

In 2018, the US renewable energy sector saw growth despite ambiguity about the effects of federal tax reform legislation and a series of new import tariffs. Some of the fundamentals that drove the growth in 2018 were declining costs of wind and solar generation, strong demand driven by state policy mandates, and corporate purchases. A favorable outlook for renewable growth is expected in 2019 and 2020 since developers may accelerate their project construction to benefit from the federal tax credits.

Data collected by the EIA reflects installed and proposed project additions for the next several years for both wind and solar projects in the United States. As expected, the figures below for wind and solar projects reveal an increase in the next couple of years followed by a decline in capacity additions after 2020.





This information represents a pipeline of proposed projects, and is subject to change based on new proposed projects and delays to planned projects. Regardless, the general direction of the trend indicates less supply available to purchase once the ITC and PTC are stepped down.

As a result, conditions in the next couple of years appear to be favorable for renewable energy purchases. There is a strong pipeline of projects and a financial incentive to complete them before 2021.

After 2020, we expect PPA prices to rise as states, utilities, and corporations seek to fulfill renewable goals, increasing competition for the projects while the pipeline decreases. It is possible that demand may drive additional growth in projects, but time will tell.

What This All Means for You

Basic economics tells us that increased demand and flat-to-constrained supply mean prices will go up. However, supply may not become constrained for another couple of years, and developers will be looking to enter into offtaker agreements as soon as possible to secure the federal incentives.

Based on the increasing demand for renewable generation from corporations, utilities, and state policies, there will be continued appetite for renewable projects. However, federal incentives will not be much help in achieving those goals, and will force developers to accelerate plans for project development. Thus, the pipeline for renewable generation in wind and solar is expected to continue to increase over the next two years, but decline thereafter.

Corporate buyers have an opportunity to jump on projects at favorable rates in 2019 and 2020 to meet renewable goals and secure long-term hedges in energy costs. Generally, negotiation over PPA agreements takes months. Therefore, if you are in the market for purchasing renewables or have sustainability commitments, we suggest starting your renewable procurement as soon as possible.

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