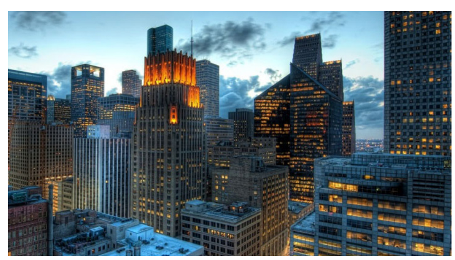
Energy Risk Report

Procurement recommendations for commercial, industrial and institutional electricity users

SEPTEMBER 2019

NATIONAL REPORT



EBWAnalyticsGroup

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Energy Risk Highlights

Electricity futures rose nationally on early September heat and soaring natural gas fuel costs. The September forecast added 55 CDDs in recent weeks, increasing late-season price risks. In ERCOT, repeated scarcity pricing triggered price advances throughout the forward curve. Further, the surge in natural gas prices increased the marginal cost of generation and lifted electricity futures.

Natural gas prices exploded recently, as bullish fundamental news triggered a major short squeeze. While a combination of increasing LNG export demand, growing pipeline exports to Mexico, and bullish weather shifts have tightened the natural gas market, the unraveling of the largest speculative net short positioning on record has been responsible for the majority of recent gains.

As a result, the rally has been driven by "less bearish" fund positioning rather than "more bullish" outcomes. The current momentum higher may soon fade, but Cal 2020 and Cal 2021 remain historically cheap.

A major bullish price shift has reshaped the autumn outlook. The September forecast has added 55 CDDs—the opposite of previous expectations—driving electricity prices higher in many ISOs. Warm weather in early October and November could potentially ease upward pressure. Longer term, while weather models broadly indicate the possibility of a warm winter, many meteorologists are relying on individual indicators that suggest a colder outcome.

Planned fall nuclear outages expected to be lighter year-over-year. More than twenty nuclear reactors will cycle offline for maintenance and refueling turnarounds this fall, reducing available generating capacity for grid operators.

Outages are not equally distributed, however, with several wholesale markets likely to see a marked increase in available generating capacity versus last fall, and others—PJM and CAISO—facing a year-over-year reduction.

In the aggregate, seasonal nuclear outages are likely to become a less pronounced source of price support during shoulder seasons as the US generating fleet moves toward gas and renewables. This transition is not without its own risks, however, as domestic power markets are more closely linked with global gas demand and increasingly rely on seasonally volatile renewables.

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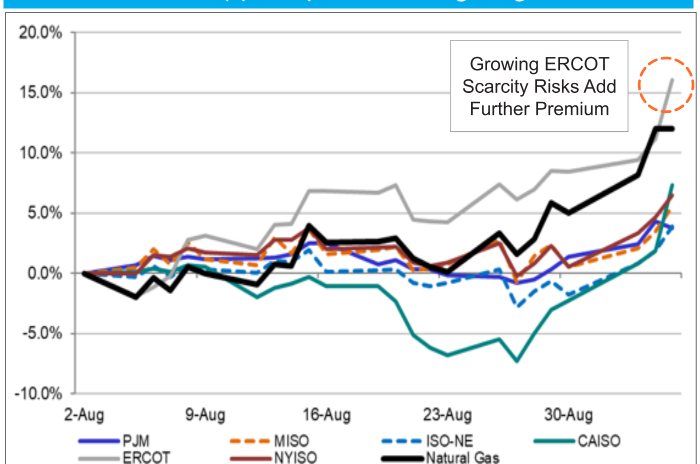
Electricity prices follow natural gas higher



Source: EBW AnalyticsGroup, Bloomberg

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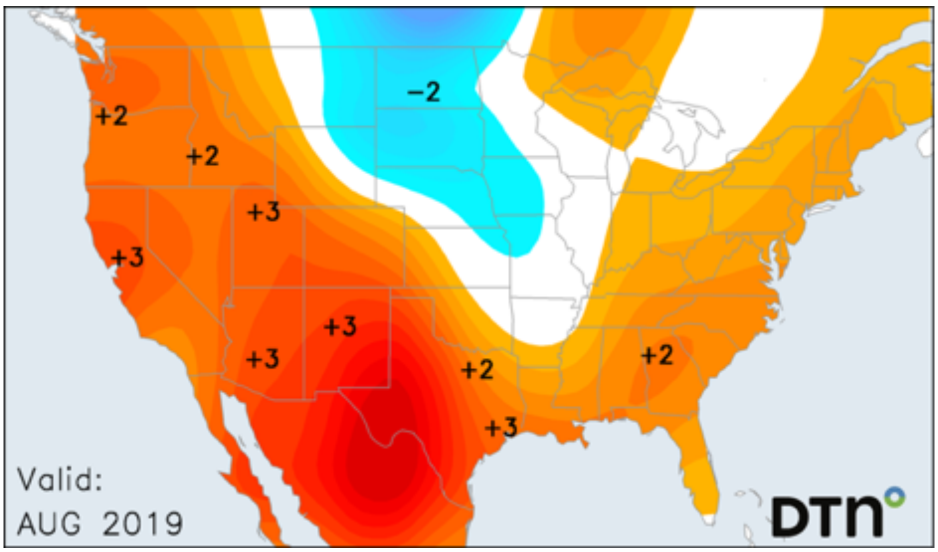
Significant Implications of Weather

September Heat Helps Trigger Price Rallies in Electricity and Natural Gas

August 2019 was the eleventh hottest on record, with 45 CDDs above thirty-year normals. August 2019 saw widespread heat across ERCOT, the Pacific Coast, and the southeastern US to propel energy costs higher for both electricity and natural gas. Many cities in Texas experienced one of the three hottest Augusts on record. Nationally, the three summer months—June, July, and August—combined to reach the sixth hottest recorded summer.

August 2019 Temperature Anomalies



Source: DTN

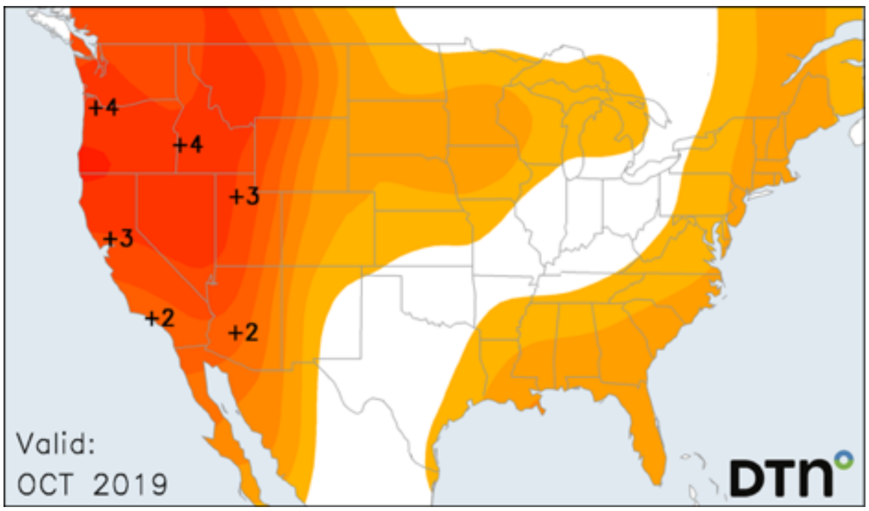
In late August and early September, Hurricane Dorian's last-minute turn away from Florida and resulting increase in cooling demand prompted a massive rally in natural gas futures—carrying electricity fuel costs and pricing higher across the US. Since the last week of August, the weather forecast added a startling 55 CDDs and 30 Bcf of power sector gas demand.

With the market entering the month heavily net short natural gas, this unexpected surge in late-season cooling was key in triggering a massive short-covering rally that pushed natural gas and electricity prices higher across the country.

Hurricane risks remain elevated through October, with the potential to bring demand destruction and cooling rains. Tropical conditions remain very favorable for additional development in the immediate term, with further storms a key ongoing price risk for end users to monitor. Any tropical storm-driven price dips, however, may be viewed as one-off events that could temporarily lower prices and become advantageous long-term procurement opportunities.

October may see warmer-than-normal weather, detracting from early-season heating demand. A slow start to the heating season could sap recent upward price momentum. Widespread warmth across the western United States, combined with bearish anomalies across the Southeast and populous Atlantic Seaboard, could hamper market enthusiasm for any continued rally. Instead, power sector gas demand is set to fall 7 Bcf/d by early October, potentially easing a tight physical gas market that has contributed to the recent run-up in pricing.

October 2019 Forecast (as of 09/09)



Source: DTN

By winter, a combination of (i) neutral El Niño Southern Oscillation, (ii) low solar cycle, (iii) warm sea surface temperature anomalies in the northeastern Pacific Ocean, and (iv) downward trending Quasi-Biennial Oscillation (QBO) raises risks for a colder-than-normal weather. Although these indicators point to the possibility of a colder winter, long-term climate models continue to extend warmth beyond autumn.

Current bullish indicators:

- The low solar cycle is correlated to increased blocking patterns channeling cold air south from Canada to elevate heating demand across the eastern US.
- A warm northeastern Pacific promotes downstream ridges bringing cold air from Canada into the Midwest and East Coast.
- A downward-trending QBO is correlated with seasonal-to-cold temperatures across the eastern half of the Lower 48.

Since a cold winter generally carries greater upside price risks than a warm winter brings downside price potential, procuring any near-term requirements at current attractive pricing is recommended.

El Niño conditions continue to fade slowly, with neutral ENSO conditions likely heading into winter. Near-neutral conditions may limit the chances of an ultra-warm winter. However, a solar minimum increases risk of blocking patterns funneling cold air masses into the Lower 48, and low sea ice may increase snowfall across high latitudes—suggesting chances for a cold winter should not be minimized.

Consumers may elect to guard against cold early winter risks—particularly if prices for electricity and natural gas generally trend lower this fall.

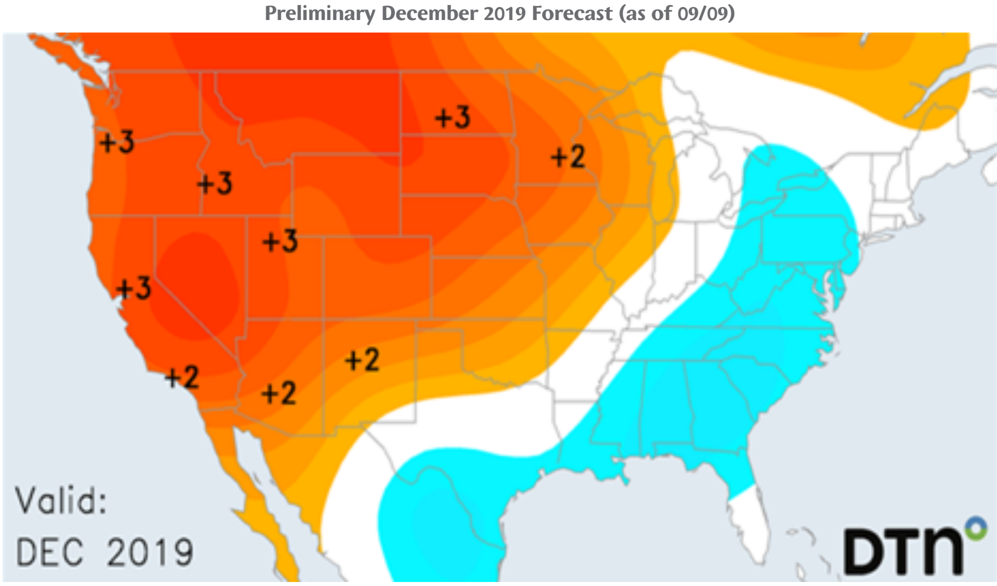
The Quasi-Biennial Oscillation (QBO) may also provide a cold signal if it flips negative in early winter. The QBO has likely peaked and may begin to slowly decline, itself a mild cold winter signal east of the Mississippi and Texas. If it turns negative by early winter, this signal can become amplified—increasing upside price risks in many ISOs.

A cold start to winter, should it materialize, is a critical upside price risk. Even after the recent run-up in prices, more upside risks remain in a cold-weather scenario. For natural gas prices, for example, speculator positioning remains net short—and further bullish fundamental news may continue or renew the charge higher in prices.

Last November, a cold start to winter sent prices sharply higher—and forward curves remained elevated for months.

A similar upside price risk, albeit less pronounced, is beginning to emerge for the coming winter as well. End users may wish to take advantage of generally favorable pricing in most ISOs to lock-in requirements through 1H2020 by the end of fall.

Preliminary December 2019 Forecast (as of 09/09)



Source: DTN

In Cal 2020, a sharp increase in wind generation could help alleviate upward pressure on natural gas and add to downward price pressure in wind-heavy regions. Despite the addition of over 8% to wind capacity, in 2018 wind output was up less than 1% year-over-year due to lower wind speeds across the country. This year, however, more than 13 GW of new wind are anticipated to be added nationally, setting up significant growth potential into 2020.

Wind-dominant regions such as MISO and ERCOT may reap larger benefits from higher low-marginal cost wind output (outside of summer scarcity-driven months). Nationally, however, a diminished call on power sector gas burn could help reduce the marginal clearing price of electricity in most ISOs.

Winter weather—particularly anomalously cold or hot outcomes—can cast a long shadow and lasting market impacts through the following year. Winter weather can cause strong fluctuations in natural gas storage inventories that can take an entire year—or longer—to normalize.

After the Polar Vortex winter of 2013-14, natural gas inventories remained well below normal, and prices much higher, until the subsequent winter. Following the extremely warm winter of 2014-15, natural gas storage reached new highs, and remained elevated for all of 2016.

During these periods, abnormal inventory levels disrupted natural gas pricing $0.50-1.00/MMBtu—causing $5-10/MWh swings in full-year electricity pricing in several markets. Although a similarly extreme winter is not the current most-likely scenario, risk-averse consumers may wish to limit outstanding risk exposure at favorable pricing. ■

Natural gas surges as fundamental strengthening sparks a short squeeze.

OUR PROJECTIONS AND RECOMMENDATIONS

Time Period	EBW* Recommendation	Price ($/MWh)				
		09/07/2019	Trend Past Month	Trend Since January	12-Month Range	Year-Ago Actual Price
Bal 2019	Portfolio	$2.52	$0.26	-$0.30	$2.21-$3.05	$3.77
Cal 2020	Portfolio	$2.48	$0.08	-$0.16	$2.37-$2.78	-
Cal 2021	Portfolio	$2.48	-$0.01	-$0.14	$2.41-$2.69	-

** See Glossary on last page*

Key Takeaways

1 Stronger fundamentals trigger major financial repositioning.
A relatively modest tightening has caused market expectations for fall weakness to dissipate—leading to a short squeeze and surging prices.

2 Weakness still possible later this fall.
Likely bearish weather year-over-year comparisons could spell renewed price weakness by later autumn.

3 LNG demand reaches new record high.
Despite soft global fundamentals, strong LNG demand this summer may portend strength for Cal 2020.

Despite Soaring Prices, Gas Futures Still Historically Cheap

NYMEX futures shot higher in mid-August as a shift in market sentiment triggered a painful short squeeze. Balance of Cal 2019 futures skyrocketed 33¢/MMBtu (14.6%), Cal 2020 gained 11¢/MMBtu (4.6%), and Cal 2021 ticked lower by 1¢/MMBtu (-0.3%). Although a stronger September fundamental outlook has been constructive for prices, the bullish shift triggered a significant short-covering rally and unraveled the largest net speculative short positioning of the past decade—leading to a much larger gain than fundamentals alone would warrant.

Autumn fundamentala strengthened 1 relative to consensus market expectations. Bullish catalysts have been plentiful: (i) LNG feedgas demand repeatedly hit new record highs in late August, (ii) the September weather forecast gained 35 CDDs, and (iii) Mexico struck a deal for increased pipeline exports from Texas.

Perhaps most importantly, previously anticipated bearish potential—from weak weather-driven demand, diminished global LNG demand, and new pipeline interconnections—appears significantly less likely to materialize. As a result, shorts have taken profits and bought back natural gas to close out their positions—sending natural gas higher and in turn forcing margin calls on other short positions and more buying.

As evidenced from the much stronger gain in near-term contracts than further out on the forward curve, the main thrust of the sharp move higher has been traders becoming "less bearish" on natural gas rather than "more bullish."

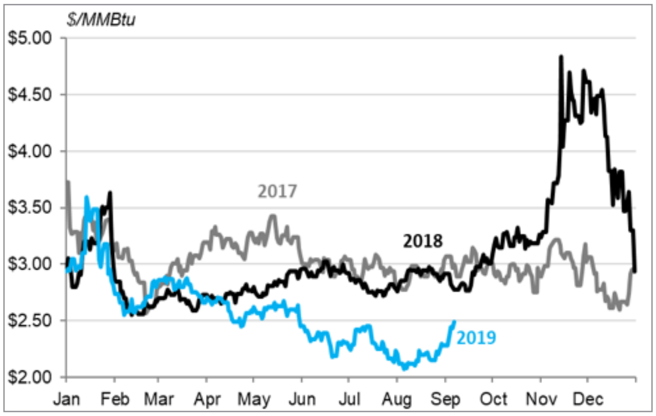
The strong move higher suggests that recent lows are unlikely to be repeated in the near term—but potential weakness threatens by late fall, as year-over-year comparisons prove bearish relative to last year's ultracold November. 2 In the immediate term, a bearish relapse is possible in the next few weeks as upward momentum runs dry and LNG market weakness remains a possibility.

By late fall, however, comparisons to last year's extremely cold November may trigger more significant bearish momentum. Early December to mid-January are currently expected to see much

NAT GAS

NYMEX Front-Month Natural Gas Contract ($/MMBtu), Since 2017

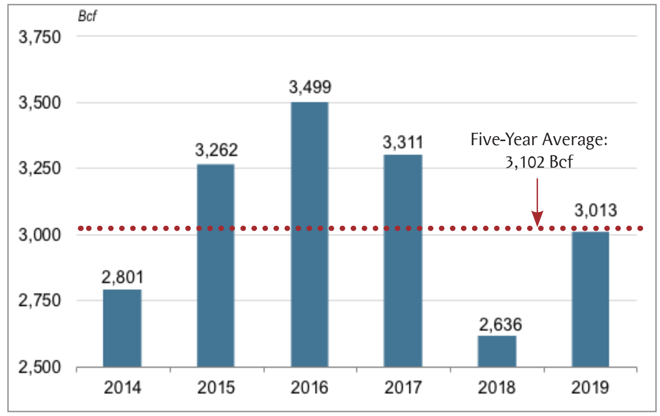
Gas pushes higher on modest fundamental strength



Source: Bloomberg

Gas in Storage in First Week of September, Last Six Years (Bcf)

2019 storage level 89 Bcf below five-year average



Source: EIA

colder weather—potentially resuming upward pressure on natural gas prices.

LNG demand reached 6.7 Bcf/d in late August and continues to churn higher despite a weak global market—potentially increasing upside price risk for Cal 2020. 3 Untested LNG feedgas demand has been an open question facing the domestic natural gas market most of the summer. LNG producers experienced weak demand due to extended outages at Sabine Pass and periodically subdued demand from Cameron LNG.

But despite low international prices and European storage 96.5% full as of early September, US LNG exports have reached new records with September-to-date figures the highest month in history.

Cal 2020 remains unkown, however, as record European inventories and surging global natural gas supplies again threaten to lower international prices—potentially shutting-in US exports and dumping supply on the domestic market to suppress prices. Still, strong LNG exports in an oversupplied market this summer point to the potential for continued strength.

Dry gas production continues to push higher, with higher-than-expected monthly data a helpful sign in maintaining downward pressure on prices in the medium- to longer term. While near-term natural gas prices are often driven by ephemeral weather, explosive growth in production has been the critical factor in steadily reducing prices during the past decade. Despite the very low prices in 2019, production growth is keeping up with or even outpacing structural demand growth—maintaining an oversupplied market and forcing natural gas prices lower.

With the 2.0 Bcf/d Gulf Coast Express starting up operations in the Permian and new gas processing capacity coming online in the Bakken, associated gas—co-produced along oil-driven drilling—is likely to continue rising and maintain downward pressure on NYMEX futures over the medium term.

We recommend a portfolio approach in the near term, with an eye to capitalizing on any emerging late-autumn weakness in the forward strip. The surge in NYMEX futures over the past month, while occurring sooner than expected, illustrates the impact of a modest fundamental shift triggering a cascading financial ripple effect.

While the upward momentum may continue in the near term, in our view it remains likely to crest later this fall—although probably at higher prices than recent lows.

For Cal 2020, strength in LNG export demand this summer points to the potential for upside price risks next year, but more opportune procurement opportunities may await later this fall.

Still, Cal 2020 and Cal 2021 are historically cheap and trading below the lowest full-year realized pricing since 2005—suggesting end users should continue steadily reducing outstanding risk exposure at favorable valuations. ■

National electricity prices rise across the board on heat, natural gas strength.

Rising Electricity Futures Highlight Price Risks

National electricity futures increased nationallyin August on hot temperatures and strong natural gas pricing, punctuated by major gains in ERCOT. 1 Electricity futures gained across the board, as the September weather outlook turned considerably more bullish and a change in market sentiment sparked a short-covering rally in natural gas futures. In Texas, repeated shortage pricing in ERCOT sent scarcity premiums soaring.

Changes at PJM West were emblematic of many ISOs, with balance of Cal 2019 futures rising $0.97/MWh (3.1%), a stronger gain for Cal 2020 of $1.03/MWh (2.6%) and Cal 2021 adding $1.07/MWh (1.2%). Regions relying more heavily on natural gas to set prices, including NYISO and CAISO, saw bigger gains as natural gas surged.

ERCOT surpassed national norms, with balance of Cal 2019 soaring $2.90/MWh (11.9%), Cal 2020 gaining $8.68/MWh (12.0%), and Cal 2021 pushing higher $4.26/MWh (6.8%).

A sharp reversal in natural gas sentiment bucked gathering bearish fundamentals to send prices sharply higher. NYMEX natural gas futures for the balance of Cal 2019 soared 25¢/MMBtu (11.3%) over the past month, with a more modest 8¢/MMBtu (3.1%) gain for Cal 2020, and Cal 2021 ticking lower 1¢/MMBtu (-0.5%).

The front end of the forward curve had been suppressed by the largest net short speculator positioning on record, but a combination of (i) bullish weather, (ii) strong LNG demand, and (iii) nascent flows on the Sur de Texas pipeline led to a short-covering rally and surging fuel prices for gas-fired generation.

Although upward pressure may relent later this fall, sooner-than-expected upward pressure reduces downside potential and suggests end users may wish to pull the trigger on outstanding near-term obligations.

Preliminary EIA data for the first half of 2019 shows a sharp decline in coal-fired generation and gains in natural gas. 2 In large part due to bearish weather comparisons with last year, total US demand was down 2.3% year-over-year in the first half of 2019. Rock-bottom gas prices helped lift year-over-year gas generation nearly 40,000 GWh (6.1%) year-over-year. In addition to a losing battle with cheap natural gas, coal retirements negatively affected coal output, down 72,000 GWh (-13.2%) vs. 1H2018.

Coal has now dwindled each year since 2010 to reach only a 24% generation market share. While it appears unlikely at this juncture, a similar decline in coal in 2020 could result in its generation share falling below total renewable output (including hydro).

Grid transformation and emerging risks to natural gas production could send prices higher. A recent series of climate town halls illustrates the growing animosity of Democrats toward fracking and fossil fuel production—even though campaign rhetoric is likely to soften if control in Washington is achieved.

Key Takeaways

1 **Electricity futures rise in every ISO.**
Repeated ERCOT shortage pricing has turbocharged upward momentum.

2 **Data confirms falling coal market share.**
Coal retirements and cheap natural gas unseat coal from its once dominant perch.

3 **Commissioner LaFleur leaves FERC.**
Her exit increases uncertainty at the Commission as the market awaits its next move.

But the potential for wholesale transformation of the grid—particularly if natural gas production costs rise concurrently—is likely to bring a hefty price tag, at least a portion of which will be incurred by end users.

Bullish weather forecast shifts and a sharp rise in natural gas prices have reset market expectations.

Commissioner Cheryl LaFleur exited FERC, breaking a 2-2 partisan deadlock and leaving only three Commissioners. 3 LaFleur officially left office at the end of August, reducing the five-seat agency to only three sitting Commissioners—the minimum required for a legal quorum.

Her exit is perceived by many as breaking a 2-2 partisan deadlock and paving the way for long-awaited action on contentious issues, including the fate of the PJM capacity market. While this is a possible outcome, FERC has historically waited for a most robust Commission before taking decisive action on contentious issues—and FERC may face a long grind ahead. If market uncertainty is prolonged, FERC may inadvertently reduce efficient investment and increase grid costs for end users.

We recommend end users more actively lock-in near-term requirements in most ISOs, while maintaining a portfolio approach for Cal 2020 and Cal 2021. Bullish weather forecast shifts and a sharp rise in natural gas prices probably reset market expectations to a degree, and as a result risk-averse consumers may want to lock-in balance of Cal 2019 futures.

While a bearish case cannot be ruled out—particularly with November weather likely to be significantly milder year-over-year—a roughly balanced risk/reward profile this fall suggests end users may wish to guard against open positions. Bearing in mind that winter weather is always a significant risk, we recommend a portfolio approach to capture potential bearish weather-normalized fundamentals in most ISOs for Cal 2020 that suggest a possibility of renewed declines. ■

Disparate Impacts of This Fall’s Planned Nuclear Outages

Every spring and fall, a considerable portion of the US nuclear fleet begins planned maintenance and refueling outages. Plant operators tend to concentrate their turnarounds during shoulder seasons to maximize availability during the pricier summer and winter periods. Between September 1st and November 15th this year, we expect twenty-one commercial reactors will be taken offline for stretches ranging from two weeks to nearly two months, removing significant quantities of low marginal cost generation from dispatch stacks.

In the aggregate, wholesale power markets are likely to enjoy a modest increase in nuclear generation this fall versus last year as less nameplate capacity is taken offline. Even so, outages and their effects are not evenly distributed: plant size, outage schedules and regional weather conditions can all produce disparate impacts for end users in different locations.

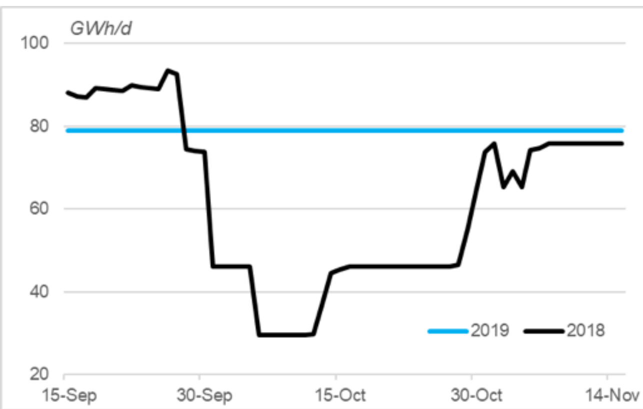
This month we examine planned fall nuclear outages in the country’s six largest wholesale markets, provide a year-over-year comparison to better contextualize the impact of this year’s outages on end-user energy prices, and conclude with a survey of emerging seasonal price drivers like LNG exports and surging renewable output.

NUCLEAR OUTAGES THIS FALL

New England to See Greater Nuclear Availability

ISO-NE end users are likely to benefit from a substantial uptick in available nuclear capacity this fall. Publicly available maintenance schedules suggest no planned outages—one shouldn't rule out a plant being unexpectedly forced offline—during the shoulder season, boosting regional nuclear output by about 17 GWh/d (27.2%) versus the same stretch in 2018.

New England Actual and Projected Nuclear Output, September-November 2019 (GWh/d)



Source: EBW Analytics, Bloomberg, NRC

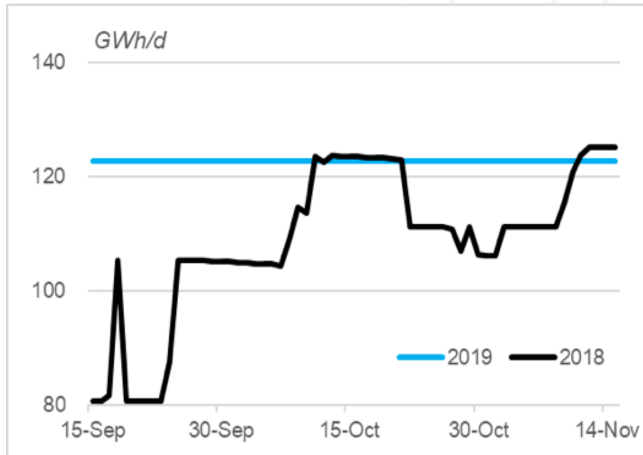
All told, minimal nuclear outages should help limit upward pressure on regional power and gas prices already restrained by the (relatively) low demand fall period.

Importantly, the retirement of the 680 MW Pilgrim nuclear plant in May structurally reduced regional low marginal cost nuclear output. Even so, the year-over-year comparison remains favorable for end users during the shoulder season.

New York: Upstate Fleet to Stay Active

Upstate New York power markets are also likely to benefit from a lighter planned outage schedule versus 2018. Currently, no plants are due for turnarounds, potentially boosting year-over-year nuclear output by 14 GWh/d (12.8%) ISO-wide between mid-September and mid-November.

New York Actual and Projected Nuclear Output, September-November 2019 (GWh/d)



Source: EBW Analytics, Bloomberg, NRC

Last fall, by contrast, both Fitzpatrick and Ginna were taken offline—removing 1.4 GW of low marginal cost generating capacity at the peak of the outage season.

Upstate end users are most likely to benefit from greater nuclear availability, but downstate consumers may also realize some indirect savings despite the Empire State's bifurcated energy market.

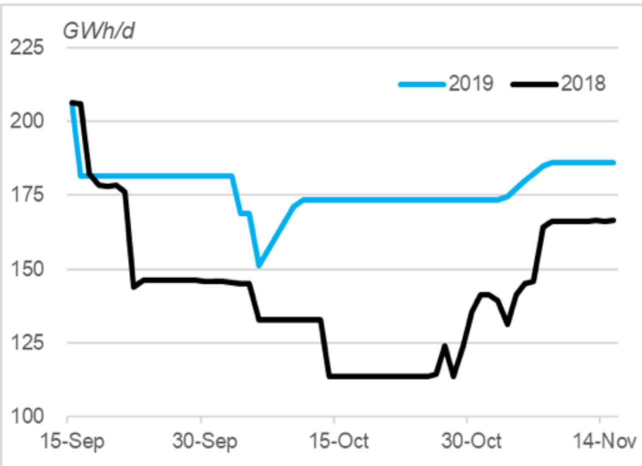
Distinct Impacts in MISO North and South

This fall, the 1.0 GW Clinton facility in Illinois and the 900 MW Arkansas Nuclear 1 (ANO 1) reactor will both cycle offline, removing low marginal cost resources in both MISO North and South.

Compared to last year, however, aggregate outages are likely to be less extreme, resulting in a projected 34 GWh/d (24.0%) uptick in nuclear output from mid-September to mid-November.

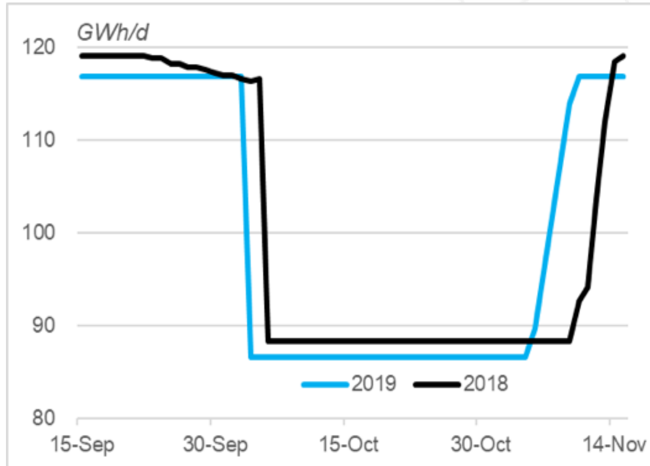
NUCLEAR OUTAGES THIS FALL

MISO Actual and Projected Nuclear Output, September-November 2019 (GWh/d)



Source: EBW Analytics, Bloomberg, NRC

ERCOT Actual and Projected Nuclear Output, September-November 2019 (GWh/d)



Source: EBW Analytics, Bloomberg, NRC

All else equal, however, end users in MISO North may see more significant year-over-year benefits than those in MISO South.

Last fall, three plants in MISO North underwent planned outages; the year-over-year increase in expected nuclear availability should exert downward pressure on regional energy prices.

By contrast, the outage at ANO 1 this year is essentially a one-for-one match with the turnaround at ANO 2 last fall, likely keeping aggregate nuclear output flat versus the 2018 shoulder season.

ERCOT to Repeat Last Year

Texas' largest wholesale power market should see nuclear availability in line with 2018 this shoulder season, with South Texas 2 scheduled for turnarounds this fall. Last year, South Texas 1 was taken offline for maintenance and refueling.

The net result: a remarkably similar fall nuclear generation outlook.

All else equal, ERCOT end users are unlikely to see much of an effect on energy costs versus 2018. In fact, the ISO's ample low cost gas and renewable generation is likely to overwhelm any marginal impact of lost nuclear capacity, though price spikes are still possible due to unexpected drops in wind output. That's likelier this year due to ERCOT's year-over-year reserve margin shrinkage—leaving end users structurally more exposed to upside price risk than last fall.

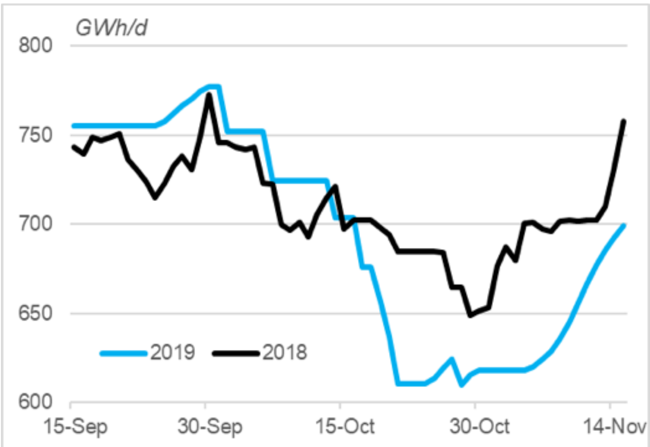
PJM: More Than 8.0 GW Offline

Unlike the aforementioned ISOs, PJM is anticipated to see a year-over-year drop in nuclear output. 8 plants scattered across the Mid-Atlantic and Midwest will be taken offline, removing up to 8.4 GW of low marginal cost output from grid operators' dispatch stacks. Last year, by contrast, only 6 reactors were taken offline.

All told, PJM could experience a loss of nearly 17 GWh/d (-2.4%) of nuclear output between mid-September and mid-November versus the same period in 2018.

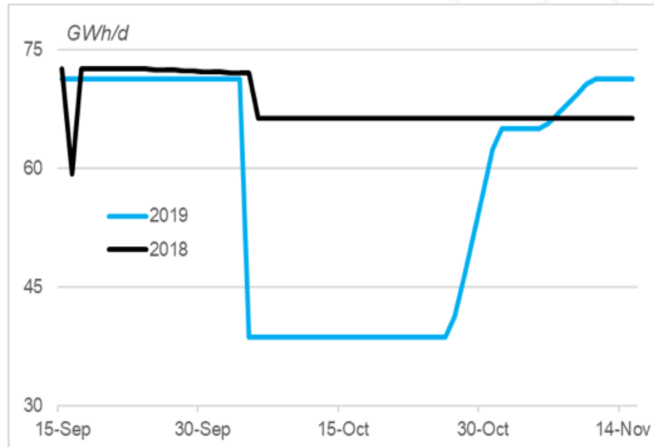
NUCLEAR OUTAGES THIS FALL

PJM Actual and Projected Nuclear Output, September-November 2019 (GWh/d)



Source: EBW Analytics, Bloomberg, NRC

CAISO Actual and Projected Nuclear Output, September-November 2019 (GWh/d)



Source: EBW Analytics, Bloomberg, NRC

The modest year-over-year deficit is likely to be most felt during the second half of October and into November, which could prove particularly impactful if the heating season gets off to a constructive start like it did last year. Planned outages are also overwhelmingly concentrated in Illinois, Pennsylvania and New Jersey, making end users in those load zones likelier to feel the impacts of lost low marginal cost generation.

CAISO: Southern California May Feel the Squeeze

CAISO may also feel the price impact of restricted nuclear output. Last year, Palo Verde 2 (1.3 GW) was taken offline in late September. Notably, when Palo Verde reactors undergo maintenance, each owner's share of plant output is reduced proportionally. Therefore, a 1.3 GW outage has a much smaller impact on power available to southern California than one might otherwise assume based on nameplate capacity alone.

This year, a planned turnaround at Palo Verde 3 will be paired with an outage at Diablo Canyon 2, taking 2.5 GW of nameplate nuclear capacity offline. All told, CAISO may see a 11 GWh/d (-15.8%) drop in average nuclear output from mid-September to mid-November.

Southern portions of CAISO are most likely to feel the impacts of lost nuclear output.

Regional restrictions on gas deliverability from Aliso Canyon magnify the impact of lost non-gas generating capacity on dispatch decisions and power costs, and the fire season could result in transmission line de-energization that restricts imports from Northern California or the rest of the Southwest.

Although fall weather is generally mild in California, structural upside price risks remain for local end users.

Conclusions: Nuclear Outages Amid Grid Transformation

The role and impact of nuclear outages on wholesale power markets is rapidly changing amid several structural changes to the US energy system.

On one hand, the price impact of maintenance turnarounds has been blunted by the transformation of the US generation fleet. Previously, both nuclear and coal plants—the two dominant sources of electricity in most markets—would go offline during the spring and

fall, significantly reducing available generating capacity and providing a material lift to shoulder season power prices.

In recent years, however, legacy retirements and an explosion in installed renewable and gas capacity have blunted the impact of those planned maintenance turnarounds by reducing market dependence on coal and nuclear resources.

On the other hand, the rise of US LNG exports has introduced a new price risk for end users to monitor. Seasonal maintenance activities and global appetites for US gas can cause significant fluctuations in LNG facility utilization and by extension feedgas demand, more closely linking US marginal generator fuel costs to international gas prices.

Now, particularly bullish or bearish conditions in US and global gas markets during the shoulder season can exert a significant impact on power prices that in some cases could overwhelm any nuclear availability considerations.

Renewables On the Horizon

The coming tidal wave of new seasonally peaking renewable capacity is also likely to exert a considerable impact on energy price formation. For example, onshore wind resources are typically strongest during the fall and spring, while solar, hydro and offshore wind tend to peak at different times of the year.

In the absence of a nationwide transmission network, certain markets—particularly ERCOT, MISO and CAISO are likely to be subject to larger differences in inter-seasonal energy prices based on the dominant source of renewable output. ■

Energy Risk Report

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Our research publications, webinars, energy price forecasting model, and consulting services identify and explain the trends that move today's energy markets. By monitoring the most important targets – including potential impact of weather, supply, core demand and other key drivers – with our proprietary models, we've been correctly assessing where the markets are likely to head next for more than a decade.

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Glossary: Our recommendations are made for a hypothetical commercial or industrial end user that consumes large amounts of electricity. With that in mind, end users must decide the timing to cover their electricity requirements.

"Wait" means that in our view prices are elevated and end users can get a better value by waiting for prices to fall.

"Buy" means that in our view prices are cheap relative to their true value, and end users are better served to buy now before prices rise.

"Portfolio" is more of a middle ground reflecting more balanced upside and downside risks. By taking a portfolio approach to procurement, end users cover a portion of requirements regularly to reduce upside risk exposure, but still retain downside potential should prices fall. In this light, a portfolio approach to procurement could be considered a cousin of dollar–cost averaging.