Energy Market Outlook

What to Expect in 2022 and Beyond

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Introduction

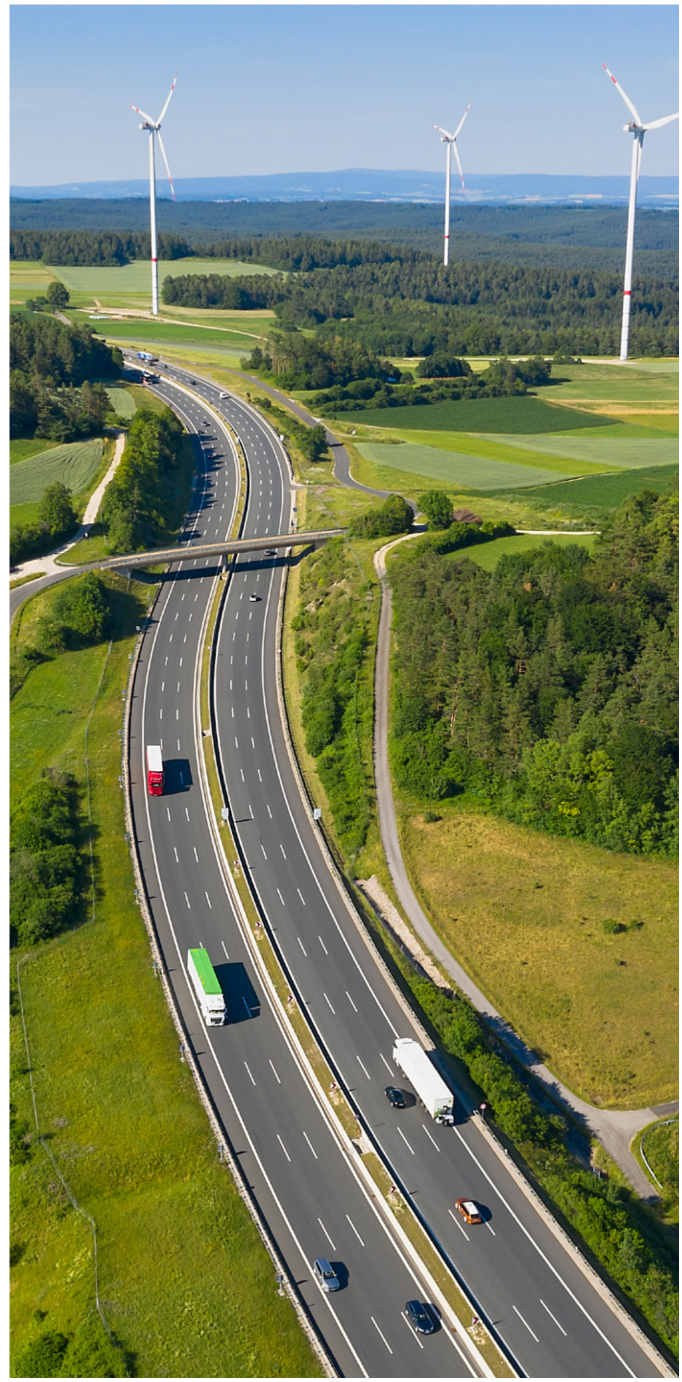
The story of energy in 2021 was the acceleration of the Energy Transition. Even in the face of the ongoing coronavirus pandemic, supply chain disruption, and other challenges, the shift to renewable energy continued. And 2022 will be no different.

Forecasts predict record-highs in renewable capacity additions in 2022, and the continued increase of renewables as a share of generation. The Biden administration set long-term net-zero targets and has already passed one bill that will support the expansion of clean energy, with hopes to pass another in 2022. At the state level, renewable portfolio standards and zero-emissions vehicle legislation are among the many tools being used to push decarbonization forward. Meanwhile, private organizations are increasingly pursuing products like PPAs, VPPAs, and more to decrease their own Scope 2 emissions.

Yet there are a variety of factors that organizations need to be aware of as they organize their energy strategy for 2022 and beyond. Global energy prices have seen significant increases in the past year, including the United States, where natural gas prices reached a 13-year high. Inflation remains a concern, and supply chain disruptions have many wondering whether there may be increased shortages of materials for renewable projects in the near-term.

This Outlook, written by Enel X's team of energy experts and market analysts, is intended as a resource to help organizations in their planning. It offers summaries of the biggest regional and national stories that may affect end users, and pairs them with 2022 forecasts and discussions of the products that can be incorporated into an energy strategy. Where possible, it offers suggestions on energy strategy.

The energy landscape continues to transform. We hope that this guide helps you and your organization keep pace with those changes.



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PART 1

National Energy Trends

The Biden Administration's Pledges and the Effects of New Policies

Summary

Once considered prohibitively expensive, solar and wind are now more affordable than nearly all other forms of energy generation in terms of levelized cost of electricity, even without subsidies. Hoping to capitalize on the momentum of the past several years, the Biden administration has laid out ambitious goals for decarbonizing the economy in the coming decades.

To reach the Biden administration's goals, solar capacity additions will have to increase rapidly in coming years. There will be obstacles to such fast growth. Yet while these challenges may prevent solar and wind from fully ramping up to the pace necessary to meet Biden's goals in 2022, renewables will nevertheless continue to grow rapidly in the coming years. Recent legislative and regulatory efforts have helped make the long-term goals more feasible, with the possibility of more support ahead in 2022.

Key Takeaways

- Renewables continue to dominate net new generation. In the first half of 2021, solar and wind accounted for 93% of new US electricity-generating capacity additions, an increase of 11 percentage points over 2020.[1] Even in the face of the pandemic, year-over-year growth is expected to once again be significant in 2022 and the years ahead.
- The Biden Administration announced goals of a carbon pollution-free power sector by 2035 and net-zero greenhouse gas emissions economy-wide by 2050. Challenges exist on the path to meeting these goals, but both are feasible with concerted efforts.
- The Infrastructure Investment and Jobs Act passed by Congress and signed by President Biden into law in 2021 will provide assistance in overcoming both near- and long-term challenges to growing renewable energy. The Build Back Better Act, which has not yet been passed, would also have a significant effect on renewable growth if it (or another package containing substantially similar energy and climate provisions) were enacted in 2022.

Doug Mills/The New York Times
Nov. 15, 2021

The Effects of New Policies

The two most significant pieces of legislation the Biden administration pursued in 2021—the Infrastructure Investment and Jobs Act and the Build Back Better Act—both contain important support for clean energy, though the Build Back Better Act has not yet been enacted. The Infrastructure Investment and Jobs Act and, if passed with its current clean energy provisions, the Build Back Better Act could help overcome many obstacles on the path to net-zero by facilitating transmission, boosting construction, funding research and development, and more. These bills could help make net-zero by 2050 feasible.

The Infrastructure Investment and Jobs Act

Signed into law by President Biden in November 2021, the Infrastructure and Investment Act provides billions of dollars of investment into electric grids and EV charging station infrastructure, as well as general infrastructure investments, all of which will have major benefits for decarbonization. For solar and wind specifically, the bill contains provisions that could help expand the country's electric grid and bolster existing and new clean energy technologies.

It could also pave the way for transmission upgrades through regulatory changes. The bill allows FERC to step in and approve the siting of new transmission projects in some instances. It would also allow the federal government to act as an "anchor tenant" for new transmission projects before transferring its share of the power lines to private entities, and the bill would enhance the DOE's authority to designate national interest transmission corridors.

Build Back Better Act

As of this writing, the Build Back Better Act's pathway forward in the Senate is still unclear. While ultimate enactment is not certain, a scaled down package including most of the energy and climate provisions remains likely. Should something substantially similar to the House-passed and current Senate Finance Committee draft energy-related provisions be enacted, it would have a major impact on the growth of renewable energy projects in coming years.

The House-passed version of the bill currently contains a variety of measures that strongly incentivize the growth of clean energy projects, most notably in the form of tax credits. The historical impact of such tax credits has been clear: the solar investment tax credit (ITC), first enacted in 2006, has been instrumental in the growth of solar over the past 15 years. The Build Back Better Act not only extends and increases the solar ITC, but gives solar the option to opt for the Production Tax Credit instead of the ITC. The current legislative text also includes a variety of other tax credits:

- Extension and expansion of the wind production tax credit (with ITC optionality)
- New stand-alone storage investment tax credit
- New transmission investment tax credit
- New zero-emission nuclear power production credit, specifically for existing nuclear power plants
- Conditioning of "full credit" value on meeting prevailing wage and apprenticeship requirements through project construction and parts of project operations
- Direct pay option for most credits, allowing monetization without constraints and frictions of tax equity market; for projects starting construction after 2023, direct pay would be conditioned on new domestic content requirements
- New clean hydrogen production tax credits

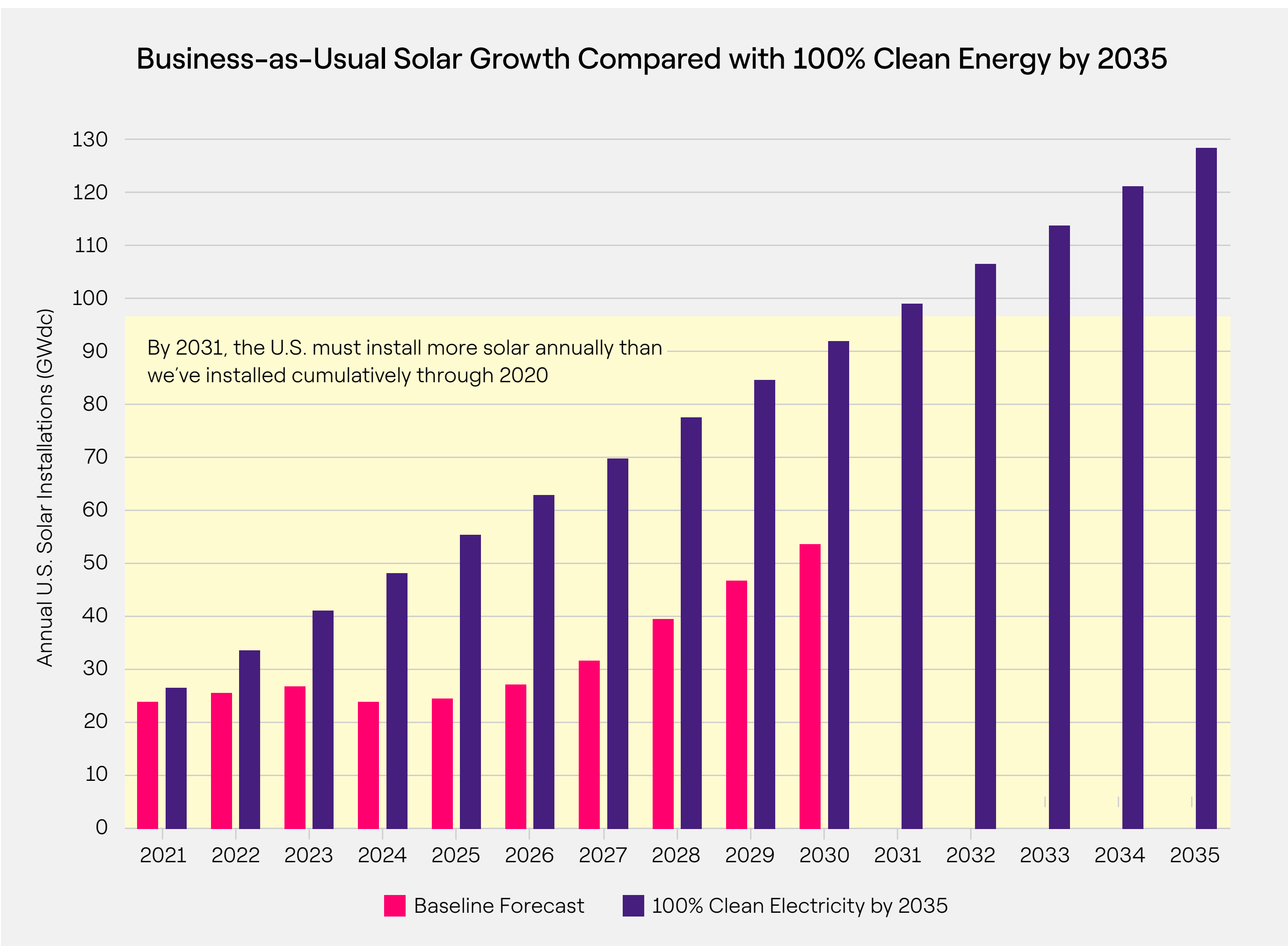
The bill also currently contains a variety of other provisions, including support for electric vehicles and fees on methane emissions. If passed in its current form, it would be very likely to speed the transformation of the energy landscape.

Should these long-term, transformative policies not be enacted, a return to short-term, lower value credit extensions is likely.

Biden Administration Goals and the Path to 2050

Last year, the Biden administration announced goals of a zero-carbon power sector by 2035 and achieving economy-wide net-zero greenhouse gas emissions by no later than 2050,[2] and in November released a report outlining a path to achieve such goals.[3]

In assessing these goals, the Department of Energy noted that it's "now possible to envision—and chart a path toward—a future where solar provides 40% of the nation's electricity by 2035,"[4] while noting that such a path would require continued innovation, advances in technology like long-duration storage, and an overhaul of the strategies used to maintain grid reliability, among other things. To reach these targets, the U.S. would have to install 30% more solar capacity on average annually between now and 2025 than in 2021 (2021 levels are forecast to reach 23 GW).[5] Then, from 2025-2030, annual new solar capacity would have to be 160% higher than 2021 levels. Although such growth would require significant investment and political coordination, Biden's vision is obtainable.



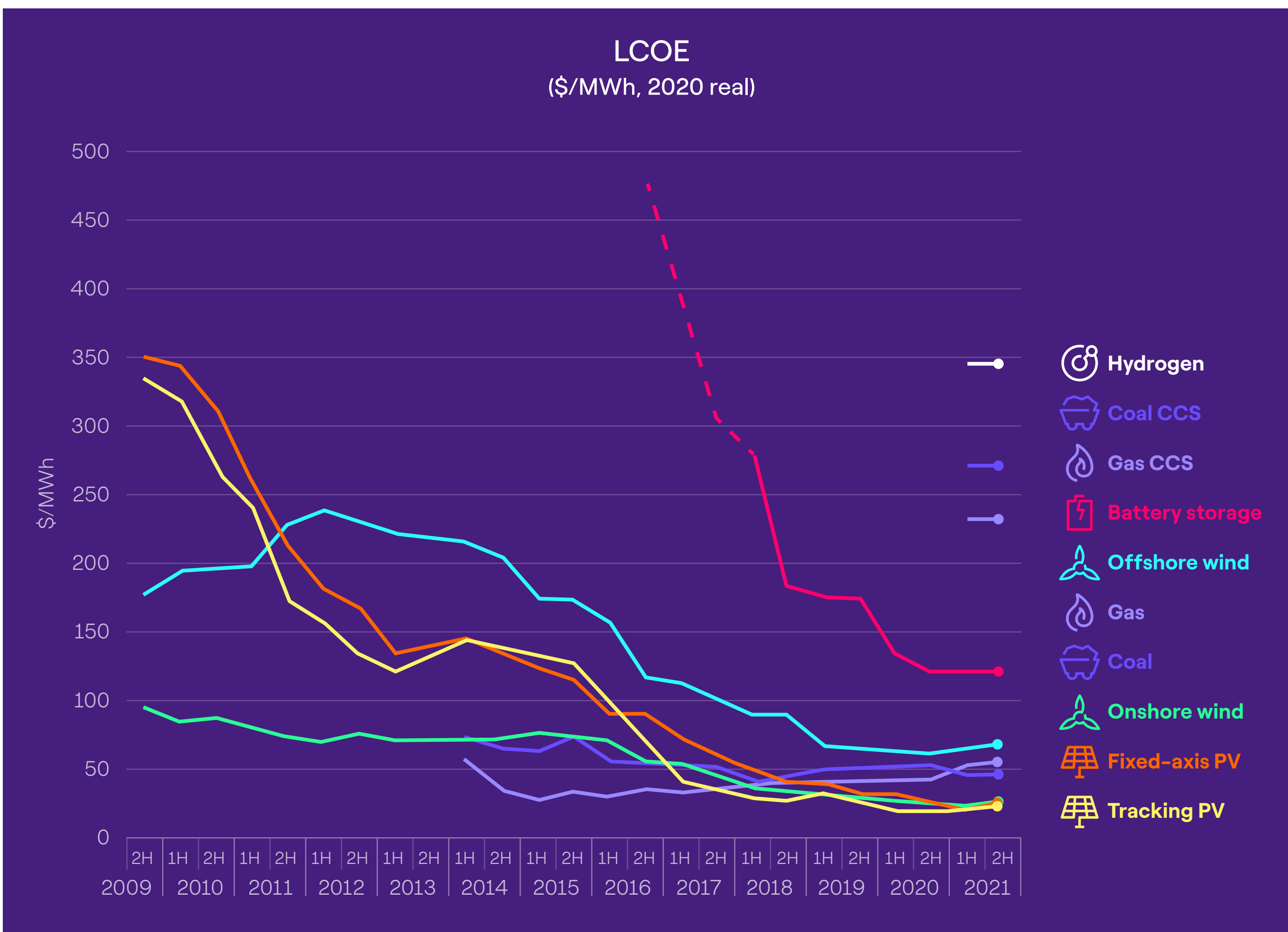
U.S. Solar Market Insight Report 2020 Year in Review; SEIA approximation of Biden Clean Energy Goal
Source: SEIA/Wood Mackenzie Power & Renewables

Reasons for Optimism: Renewable Energy Cost Advantages and Increasing Market Share

The US is not presently on pace to reach Biden's new goals at current levels of solar capacity additions, but a look back at the past decade shows how quickly things can change. In 2011, wind and solar combined accounted for less than 40% of new US electricity-generating capacity.[6] By 2021, wind and solar accounted for 93%, an increase of 11 percentage points over 2020 alone. Solar now accounts for more than half of new US electricity-generating capacity additions annually.

By now, even in the absence of subsidies, solar and wind are the cheapest forms of energy, after being considered prohibitively expensive not much longer than a decade ago.[7] The reasons for this rise are multi-faceted—in part, increased demand led to growing understanding and falling prices in a virtuous cycle.[8]

Even so, solar and wind account for less than 10% of monthly generation in the US in 2021 through September 1.[9] The question now is both how far and how fast renewable energy penetration in the United States can go, with rapid solar expansion expected to do the lion's share of the work.



Dashed line is derived LCOEs based on historic battery pack prices. CCS is carbon capture and storage. Source: BloombergNEF.

The Near-Term Obstacles: Supply Chain Disruption, Inflation and Interconnection Queues

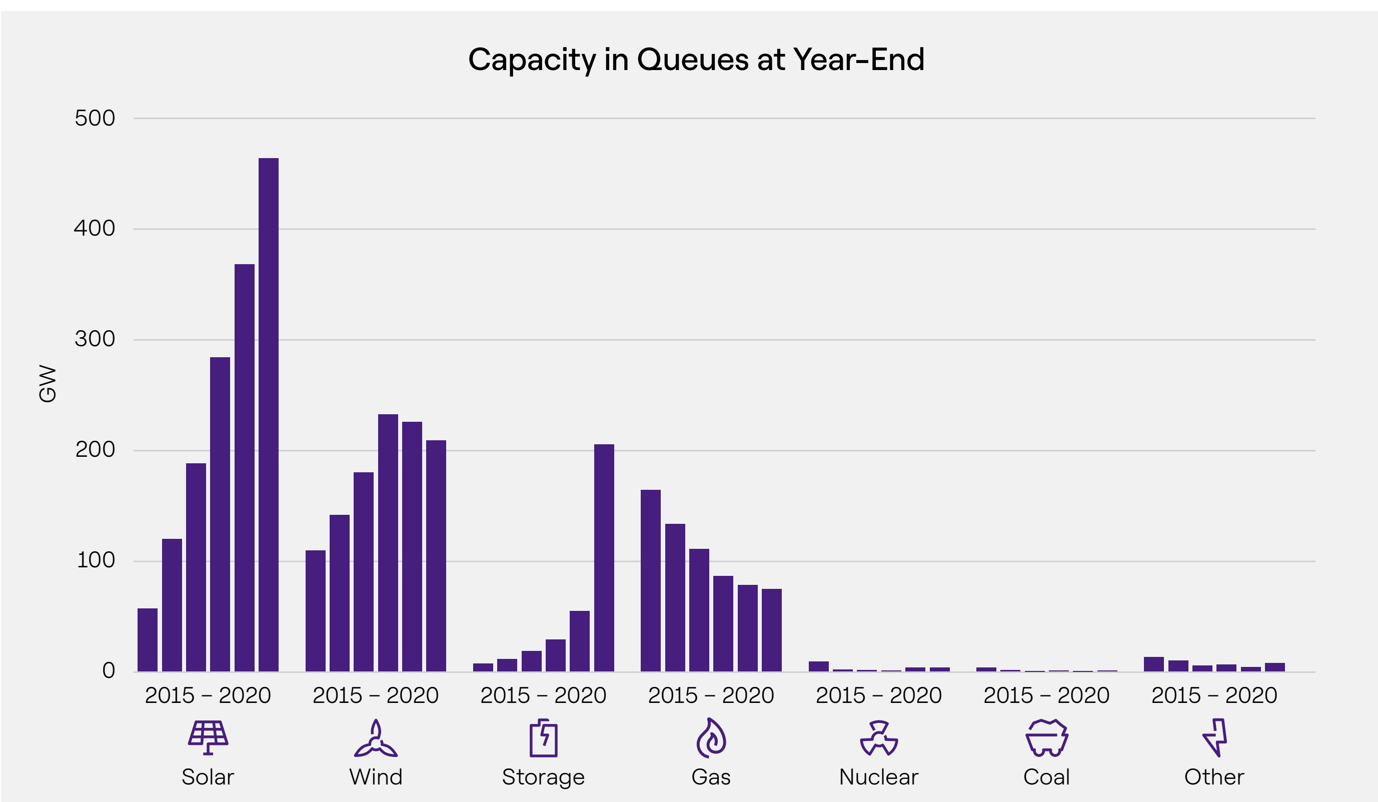
Although the outlook for net new renewable energy capacity in 2022 remains strong, a number of constraints could prevent capacity additions from immediately ramping up to the pace necessary to achieve the Biden administration's goals.

Even after a record Q2 for solar deployments, it became clear that supply chain and trade issues had begun to affect the solar industry.[10] In a joint report, the Solar Energy Industries Association and Wood Mackenzie noted that in Q2 2021, "for the first time since Wood Mackenzie began tracking system price data, prices are up both quarter-over-quarter and year-over-year across every segment."[11] The largest increases included inputs like steel, as well as elevated freight costs.

It remains unclear how soon these issues will be resolved. Many analysts expected both supply chain issues and inflation to be transitory in mid-2021,[12] but both persisted through the year.

Yet it's important to note that, even in the face of the uncertainty surrounding these issues, most analysts remain optimistic about continued renewable energy growth and new records this year.

Beyond the supply chain, transmission remains a challenge. Studies have found that the US electric transmission grid may need to triple in size by 2050 to meet net-zero goals.[13] Interconnection queues have grown rapidly in recent years, as seen in the accompanying chart,[14] with solar, wind, and storage making up the vast majority of such projects. The queue for solar, measured in GW, more than doubled between 2017 and 2020 alone. The Federal Energy Regulatory Commission, with a 3-2 Democratic-appointed majority after the swearing-in of Willie L. Phillips, has made transmission a major focus in recent months, specifically looking to address interconnection as a first step.[15]



Source: Rand, Bolinger, Wiser, Jeong, "Queued Up," Berkeley Lab

Electric Vehicles and Smart Charging Infrastructure

Summary

Electric vehicle (EV) sales will continue riding all-time highs to outpace previous projections through 2025. Given the rapid increase in EVs on the roads, the pace of electric vehicle supply equipment (EVSE) deployment must increase exponentially between now and 2030. Both the US Infrastructure Investment and Jobs Act (IIJA) and private enterprises are pushing to close that gap and support further EV growth.

Key Takeaways

- The US Congress has made landmark investments in the EV industry—at least $13.6B from the newly-passed IIJA, and California increased funding for ZEV infrastructure 600%.
- EV sales for the first half of 2021 were up 103% year-over-year despite ongoing chip shortages, pushing analysts to improve outlooks for EV adoption through 2040 by as much as 20%.
- Zero emission vehicles' share of sales in California was up 48% year-over-year.
- Commercial EV charging station deployments are set to rise exponentially in 2022 with a $7.5 billion investment from the IIJA as well as state and local incentives and regulations.
- Analysis shows smart charging can save EV drivers up to $1,070 annually compared to gas-powered cars, positioning this technology to dominate the residential EV charger market in the coming years.

Historic Government Spending Will Lower EV Barrier to Entry

The newly passed IIJA earmarks $7.5 billion to expedite building the national network of public EV charging stations, $5 billion for the purchase of low- and no-emission school buses across the country, and another $1.1 billion in research and grant funding for battery technology.[16] In addition, it makes more than $12 billion in annual grant funding eligible for EVSE infrastructure projects.[17]

At the state level, the California Energy Commission passed a three-year $1.4 billion plan to expand EVSE and hydrogen refueling, increasing its EVSE support budget by 600%. Through investments like these, expect the upfront price of new all-electric large vehicles and SUVs to reach parity with gas-powered vehicles by 2023, with small and medium vehicles only one year behind that pace.[18]

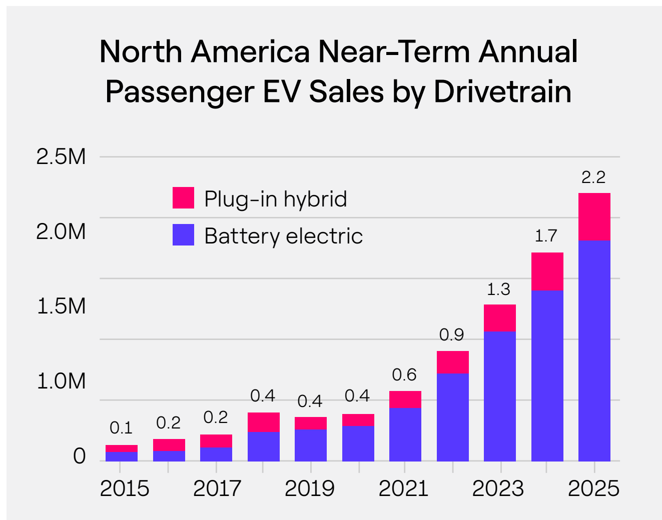
EV Sales Broke Records, Expect More of the Same

Sales in the first half of 2021 were stronger than any other half-year on record, and Bloomberg estimates full-year EV sales will be just as impressive despite ongoing semiconductor chip shortages.[19] In California, ZEVs claimed 11.5% of all new car sales in the first three quarters of 2021, up 48% from 2020.[20] Taking note, both Bloomberg and the International Energy Agency have increased their outlooks for EV's share of total vehicle sales through 2040 by as much as 20%.

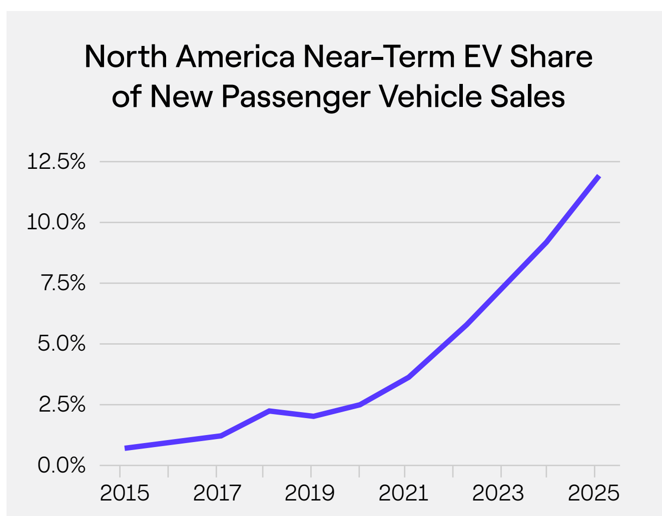
Companies around the world are accelerating this trend by electrifying their vehicle fleets and installing charging stations both at offices and employees' homes.[21] Fleet electrification will ultimately generate a larger used EV market, driving down the cost of EVs and aiding adoption.

Likewise, the arrival of new electric vehicle classes is convincing more mainstream buyers into making the switch. Chief among them is the electric pickup truck, which will hit the market in 2022 after more than a year of delays. Keep an eye out for Rivian's R1T to set the tone,[22] closely followed by Tesla's Cybertruck, GM's Hummer EV, and the Ford F-150 Lightning.

2022 Rivian R1T



Includes Canada and the US. Source: BNEF.



Includes Canada and the U.S. EV includes battery-electric and plug-in hybrid electric vehicles. Source: BNEF.

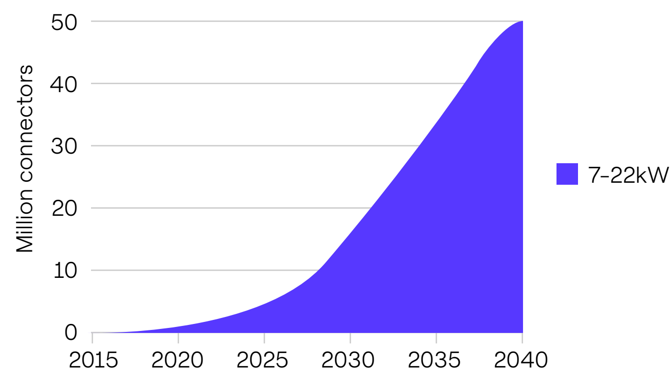
EVSE Installations Will Ramp Rapidly

By 2030 Bloomberg estimates that the US will require 1.5 million public chargers to service the EVs on the roads.[23] That number is triple the Biden Administration's current 2030 target of 500,000. As of early November 2021, the Department of Energy reported just 111,817 public chargers in operation nationally, only a 4.6% increase from 2020.[24]

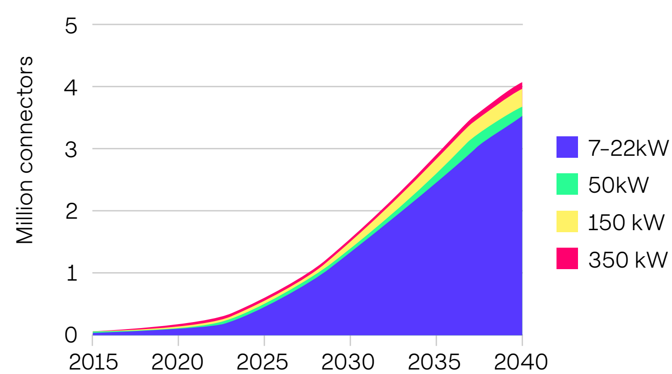
The pace of EVSE installation must increase dramatically over the coming decade, and developments in late 2021 suggest it will. While the US Congress approved $641 million for charging infrastructure deployment in 2020, the new Infrastructure Bill tacks $7.5B onto that, and there are also over $3 billion of approved or pending utility filings for charging infrastructure roll-out in the mix.

Charging Infrastructure Roll-Out for Passenger Vehicles and Vans in the U.S. to 2040

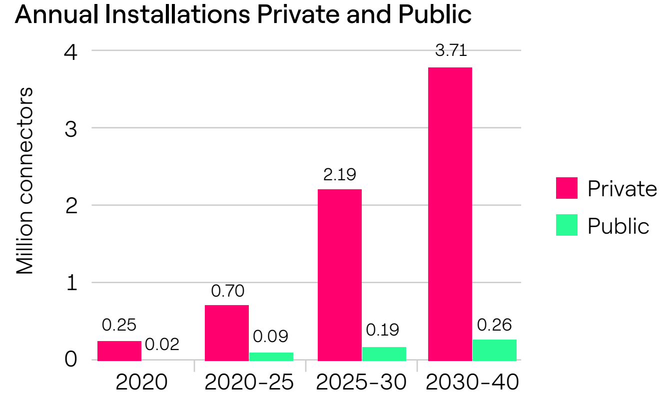
Cumulative Private



Cumulative Public



Annual Installations Private and Public



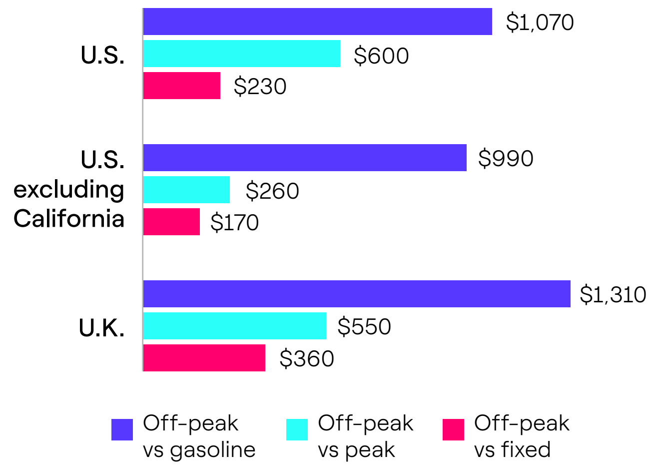
Source: BNEF. Annual public installations in 2020 may differ from those highlighted in other BNEF reports as the outlook does not include 3kW chargers or CHAdeMO fast charge connectors. Annual private installations are estimated.

Smart Chargers to Deliver Cost and Carbon Savings for EV Drivers at Home

Utilities are switching more of their residential customers to time-of-use based electricity tariffs—which charge customers different amounts per kWh depending on the time of day—in an effort to better balance the grid. All three of California's large utilities will finish transitioning their residential customers to time-of-use rates in 2022, joining the wave of power providers across the country doing the same. This transition will make smart charging at home increasingly valuable to EV drivers.

Because only smart chargers can combine their owners' tariff data with charging needs to prioritize charging during off-peak hours when electricity is cheapest, they have the potential to save American EV drivers up to $1,070 annually on fueling costs. Smart chargers can also reduce charging-related carbon emissions as much as 31% through tariff optimization.[25] With 60% of EV drivers already purchasing Level 2 chargers for their homes, this combination of cost and emissions reductions will likely make smart chargers an even more popular choice for residential charging throughout the decade.

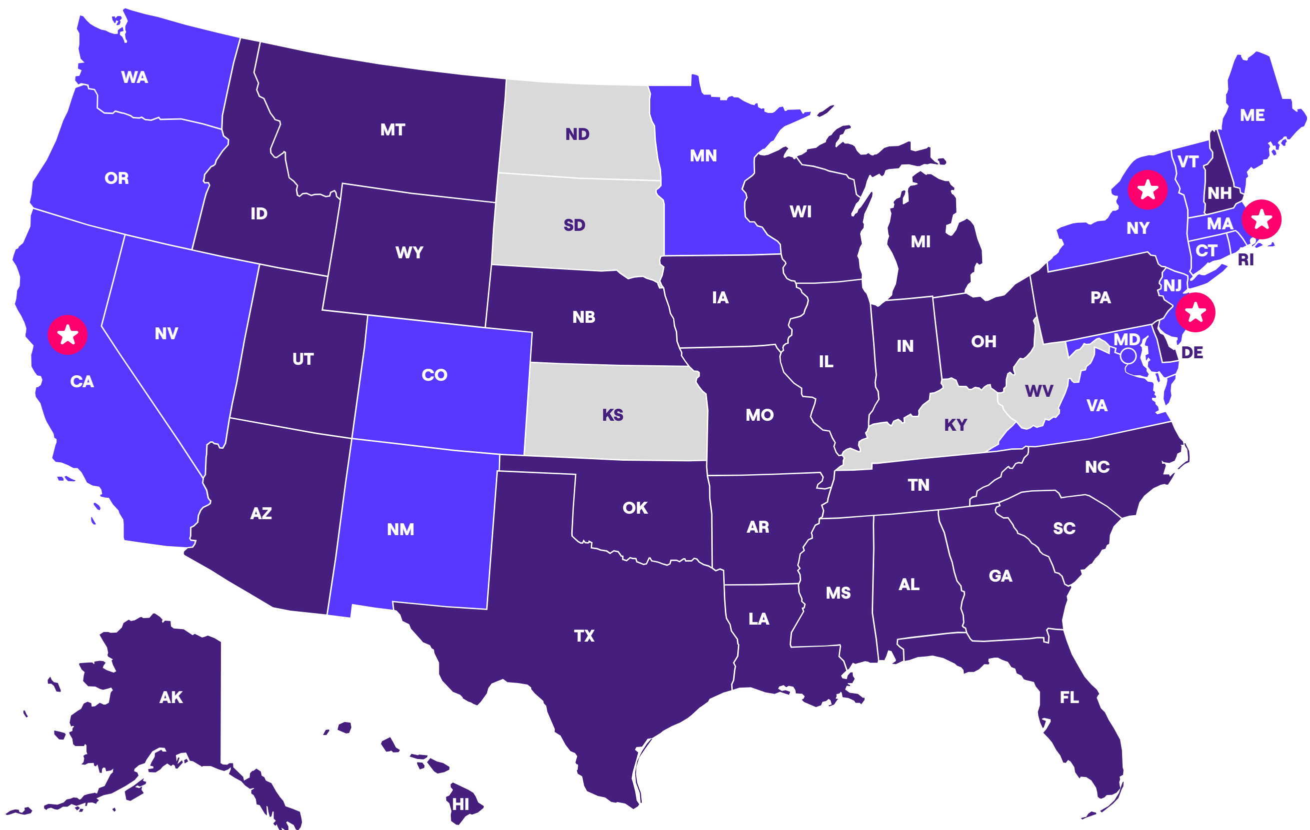
Annual Fuel Savings Using Off-Peak Charging



Source: BNEF. Median electricity rates hide extremes of some utility tariffs. Annual driving cost comparison compares a BEV on different electricity tariffs with a gasoline vehicle.

Assumptions: *all vehicles drive 15,250km/yr; the average BEV consumes 2,288 kWh/yr; cost of gasoline is $1.03/liter in California, $0.77/liter in the rest of the U.S. and $1.71/liter in the U.K.; vehicles consume 9.4 litres/100km in the U.S. and 5.7 liters/100km in the U.K.*

State and National Policies Will Push EV and EVSE Growth



Electric vehicle and EV charging incentives
Zero-emission vehicle (ZEV) mandate
100% zero-emission vehicle sales mandate

Source: National Conference of State Legislatures

Zero-emission Vehicle Policies in the US

For both EVs and EVSE, purchasing incentives are becoming the norm at national and state levels. As of July 2021, at least 45 states and the District of Columbia offer incentives to support deployment of EVs or alternative fuel vehicles and supporting infrastructure.[26] With such strong tailwinds behind EV adoption, look for state governments to expand into EV manufacturing incentives next, as Illinois[27] and Arkansas[28] have.

Likewise, emission standards are popping up across the country. To date, at least 16 states have adopted both California's low-emission vehicle (LEV) and zero-emission vehicle (ZEV) standards, requiring manufacturers to sell a certain number of EVs per year.[29] Minnesota will be the next state to adopt California's standards,[30] leading the way for Midwestern states, followed closely by Nevada.[31] As pressure mounts for states to meet their decarbonization commitments, expect more states to join the fold and update new building codes to require more EVSE.

Battery Storage

Summary

For stationary energy storage, 2021 continued the trends of 2020. Battery costs continued to drop, even as raw material and production costs rose. Globally, capacity additions continue to surpass projections with no slow-down in sight. While most of the growth has been in utility-scale storage projects, residential and commercial projects continue to grow steadily.

As we move further into 2022, we can expect installation prices to remain relatively flat. Recent incentives in the United States have provided a multitude of opportunities for storage projects. We will likely see capacity of commercial and residential storage boom in 2022.

Key Takeaways

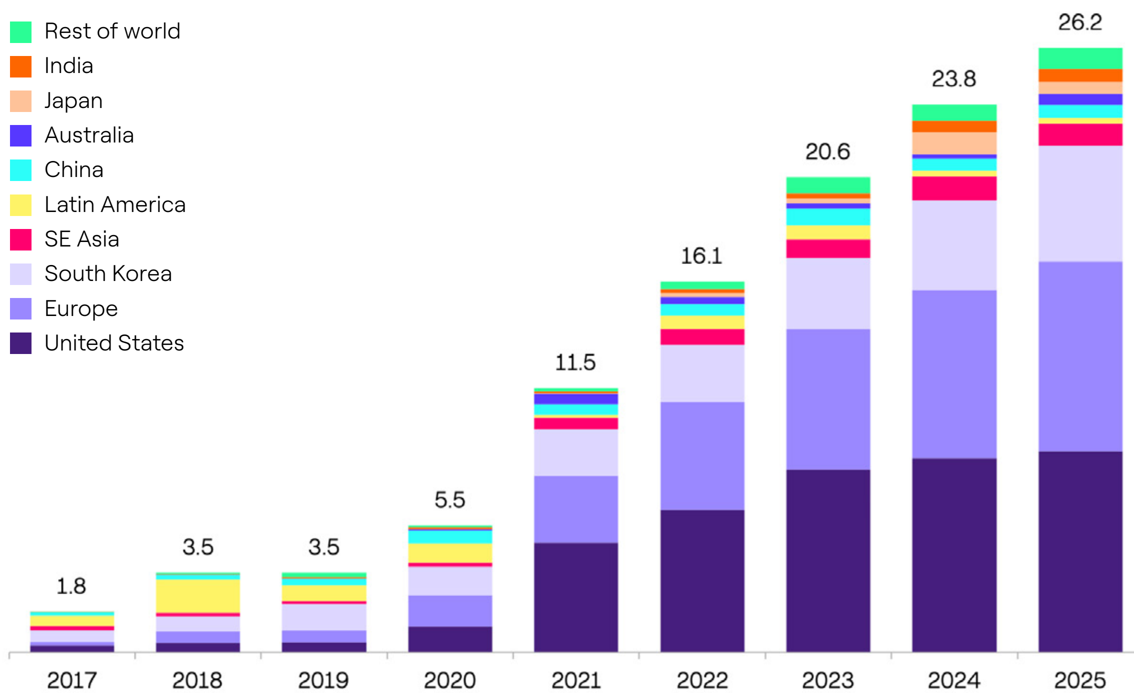
> Battery prices continue to fall, despite the rising costs of raw materials and inputs amid the disruption in supply chains worldwide.

> Eventually, those rising input costs will likely cause upward pressure on battery prices, which are already expected to slightly increase in 2022.

> If the Build Back Better bill passes and includes the 30% Investment Tax Credit for stand-alone storage that exists in the current version, many states could become financially viable locations for energy storage in 2022.

Battery Deployments Continue to Grow in 2021

Global Energy Storage Build (GW)



Source: BloombergNEF

Batteries will play a crucial role in smoothing out the generation curves associated with intermittent generation. Unlike more traditional electricity generation sources like fossil fuels, resources like solar PV and wind are less able to control when they generate electricity. Batteries can help combat the "peaky" demand of the grid to store energy when available and dispatch when needed. It is not necessary to "overbuild" intermittent generation if battery storage is optimizing the relationship between supply and demand. Battery storage and renewables are highly complementary, as evidenced by rapid growth in renewable-heavy states like Texas.

In 2021, US energy storage once again surpassed new milestones even as the coronavirus pandemic continued to disrupt business and global supply chains. Forecasts indicate that capacity of utility-scale energy storage tripled by the end of 2021, totaling nearly 6 GW, up from 2 GW at the end of 2020. Q1 and Q2 saw combined deployments of 626.5 MW, roughly 12% of the expected MW for 2021.[32] Q3 alone saw over 1.1 GW of both front-of-the-meter (FTM) and behind-the-meter (BTM) deployments.[33] FTM systems have largely driven the growth, totaling nearly 89% of deployments, even though companies expect many projects delayed into 2022. Overall, total capacity in 2021 is expected to nearly quintuple to 14.5 GWh as Q4 closes out.

Global deployment trends align with US storage forecasts, reaching 12 GW/28 GWh in 2021, largely driven by China and the US.[34] China alone is expected to add nearly 2.9GW/5.5GWh of storage capacity in 2021, more than doubling capacity added in 2020.[35] Europe, the Middle East, and Africa carry similar trends, adding nearly 2.0GW/2.7GWh of storage by the end of 2021. While most of the capacity additions are from utility-scale storage (roughly 80%), residential and commercial projects are projected to quickly increase through 2025.[36]

Prices Continue Falling, but Supply Chain Problems Remain

Prices in storage equipment, construction, and operation have fallen drastically over the last decade. Installed capacity prices for utility-scale energy storage has fallen from $2,100/kWh in 2015 to $589/kWh in 2019.[37] Utility-scale energy storage tends to be cheaper on a $/kW basis than commercial stand-alone storage, but similar price reductions have been seen on stand-alone BTM projects as well.

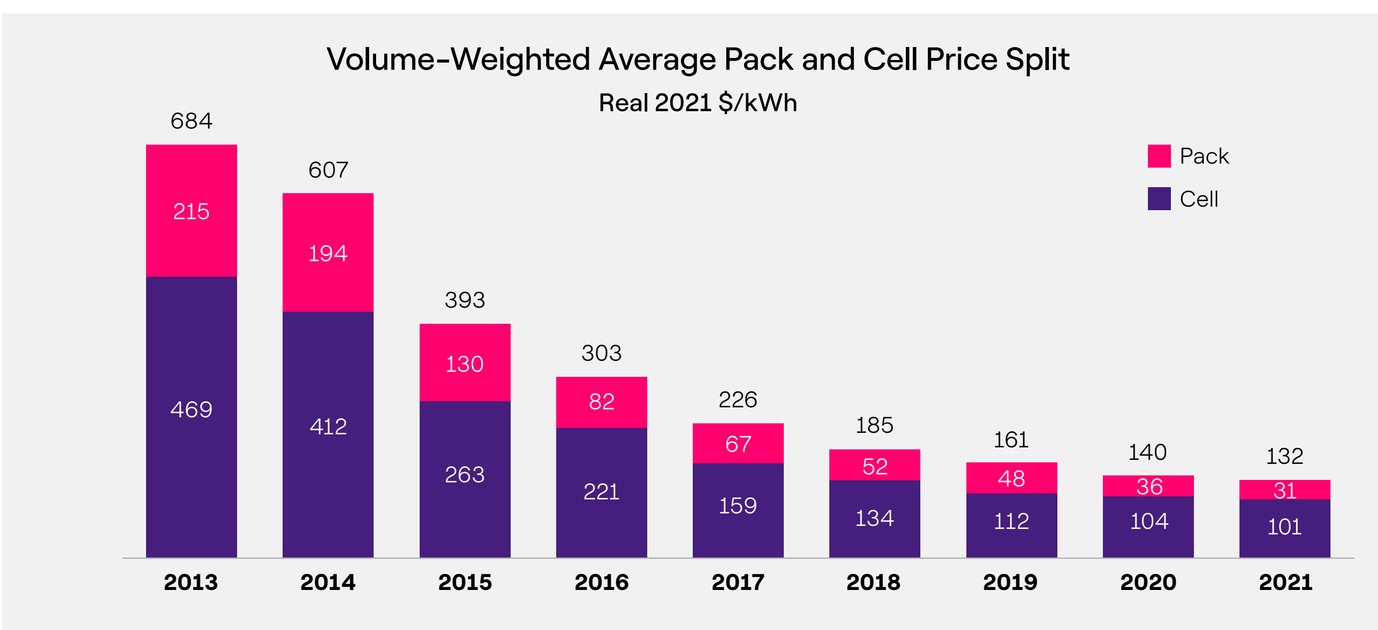
US-based commercial stand-alone storage prices for 2-hour systems vary based on different studies—one report found prices between $710-546/kWh for Q1 2021, while another found the price for a generic 2-hour system in 2021 was $400-427/kWh.[38] The differences between projects varies heavily based on geographic location of the systems, local government incentives, and construction costs. Regardless of the differences, costs for full installation and operation of the storage systems are expected to drop by another 40% by 2030.[39]

In the near-term, it's important to be aware of the ongoing rise in prices for raw material costs over the last year. The industry expects the price for raw materials to remain high until the end of 2022, but with less disruption to supply chains from the pandemic calm prices are expected in

Lithium processing plant

2023.[40] Lithium prices have more than doubled from October 2021 to December 2021, which has caused concern.

However, based on volume-weighted average prices of battery packs, the drastic increase in raw material prices is only expected to have a small effect on the prices of storage systems. By the end of 2021, prices were estimated at $132/kWh whereas 2022 pricing is expected to rise to only $135/kWh.[41]



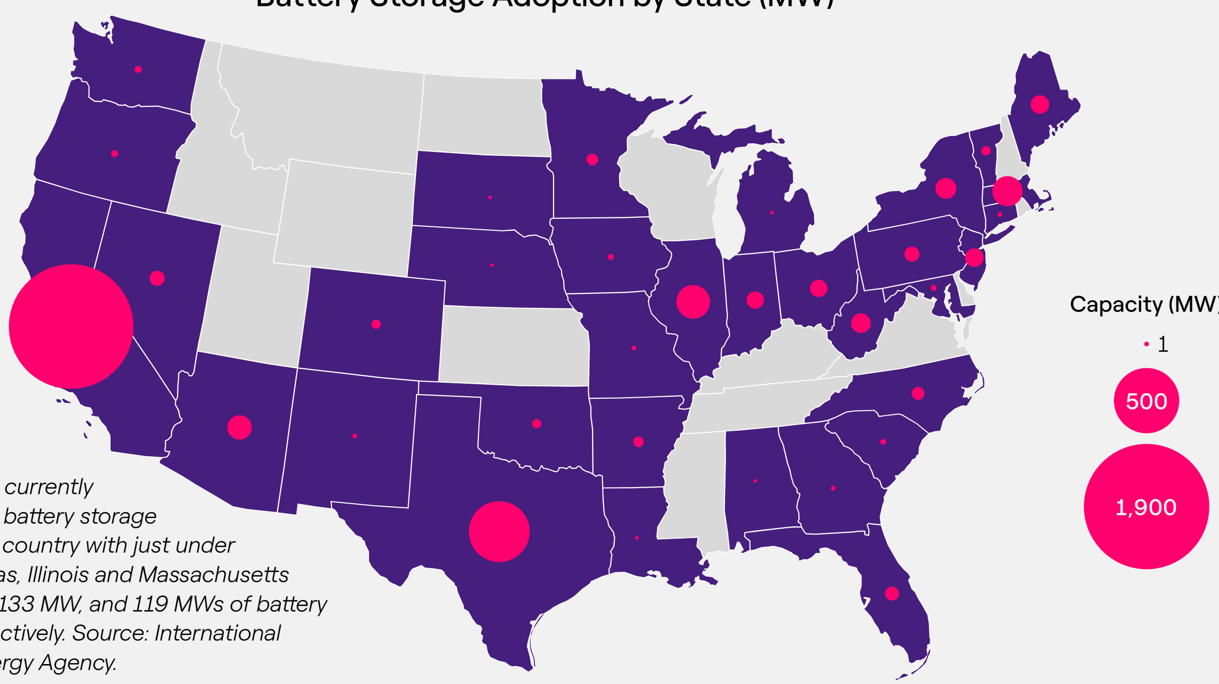
Source: BloombergNEF

More Markets Could Become Viable for Standalone Storage

The proposed Build Back Better Act would provide massive incentives for renewable infrastructure.

Passage remains uncertain, but if passed in its current form, Build Back Better will extend a 30% tax credit on a variety of renewable projects which will help to lower the levelized cost of these technologies, specifically wind, solar, and energy storage.[42] Previously, certain restrictions did not allow stand-alone storage to qualify for the ITC, so the recent amendment allows more flexibility and opens new markets in the US. Some of the states where we foresee opportunity post-ITC are highlighted below.

Battery Storage Adoption by State (MW)



As of 2021, CA currently has the largest battery storage portfolio in the country with just under 2,000 MW. Texas, Illinois and Massachusetts have 430 MW, 133 MW, and 119 MWs of battery capacity, respectively. Source: International Renewable Energy Agency.

Illinois

Existing grid incentive programs in addition to favorable electricity pricing already put Illinois in a good spot for energy storage opportunities. Combined with the ITC, Illinois would become a state that could see storage systems become financially advantageous.

Michigan

Consumers Energy recently changed its approach to pricing electricity to better reflect the actual cost of generation during peak hours, which ultimately raised prices for consumers throughout Michigan.[43] These higher demand charges are favorable for energy storage opportunities and customers looking to reduce their peak charges.

North Carolina

The preexisting Coincident Peak program in North Carolina is already favorable for energy storage opportunities, given that consumers would be able to reduce their use during those hours to save money. With the addition of the ITC, North Carolina becomes a favorable opportunity.

Other States

CA, NY and MA all have local incentives that already allow for affordable renewable development, but the ITC will allow the development of more projects in those areas and increase the total capacity greatly. Other areas such as TX, AZ, CO, and states within PJM's service territory are on the brink of a storage boom. If the Build Back Better bill is passed, the ITC will help jumpstart the development of projects in these geographies.

The Importance of Batteries in the Energy Transition

Battery storage paired with behind-the-meter solar can help optimize your demand and reduce the need to purchase grid electricity during expensive hours. Battery storage systems provide curtailment during expensive hours, but also curtailment during the right hours—for example, hitting the ICAP window if you are in the ISO-NE, NYISO, PJM (multiple hours), IEOSO (multiple hours), or CAISO (depending on supplier and location). A 1 MW reduction in capacity tag from a battery storage system would save a customer in COMED about $80,000 if the battery was used during 2020 peak hours.

Battery storage systems also add resilience and reliability to your building or home, and in some cases, provide the potential to island from the grid if the battery storage system is large enough and connected to a microgrid.

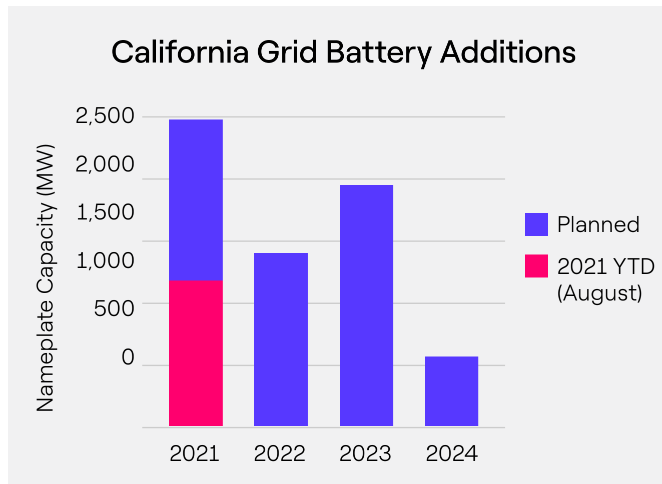
Storage in California: A Microcosm of Energy's Future

To better understand how batteries will be a crucial part of the renewable energy future, consider storage in California where utility-scale battery storage has taken a lead role. With the looming retirement of more than 10 GW of essential generation from natural gas and nuclear in addition to inability to forecast hydro availability due to the worsening drought outlook, it is essential that batteries fill the role of dependable quick start generation. According to EIA data, California added a record amount of battery storage in 2021, totaling roughly 2.5 GW.

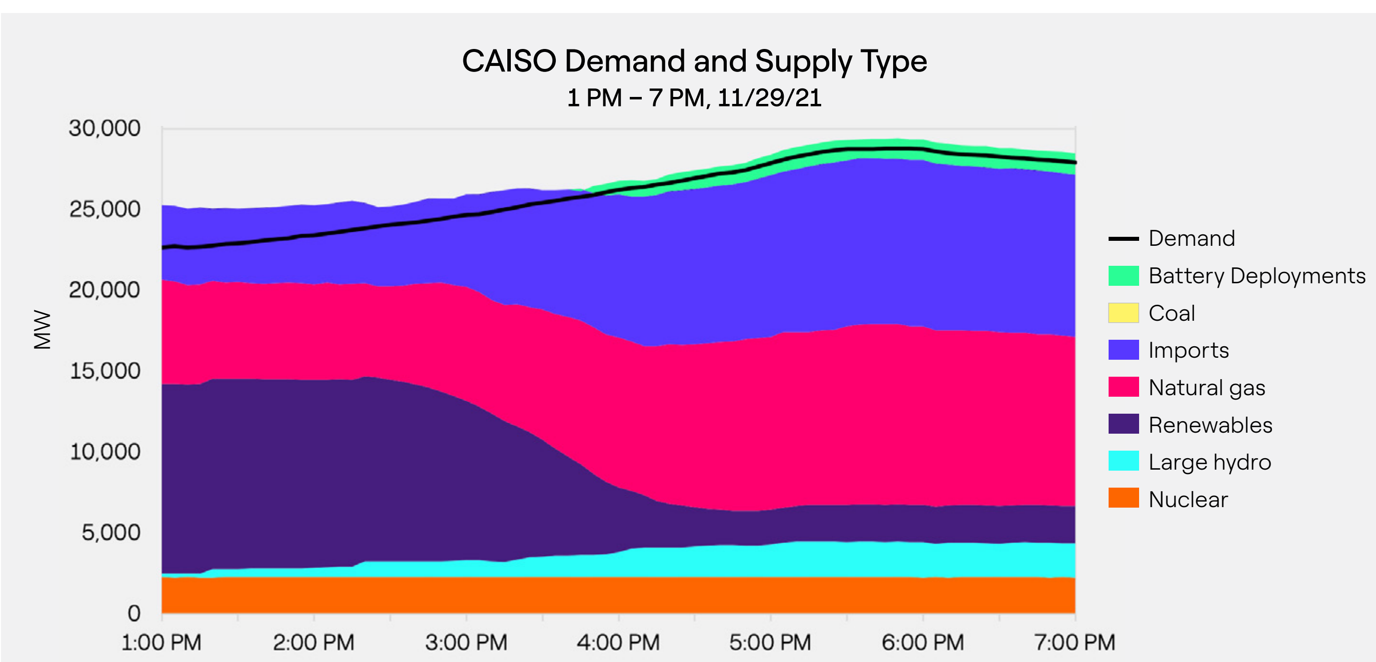
Since July 2021, batteries in CAISO are routinely discharging more than 1 GW of capacity in evening hours as solar output wanes and grid demand increases. While battery additions to the grid are beginning to chip away at the gap, their contribution to the grid is still dwarfed by use of in-state natural gas resources and imported power (coal/gas).

The accompanying graph illustrates the supply and demand curves from November 29, 2021. In the three hours between 2PM and 5PM, total demand increased while renewable output declined, leaving a roughly 13 GW shortfall. While battery output increased to more than 1.3 GW that evening, this made up only 10% of the gap, with the remainder met by natural gas, imports, and large hydro.

While this is a promising demonstration of the capabilities of batteries, this is from a shoulder season month where evening increases in demand are less extreme than volatile summer months. California will need to increase efficiency in the deployment of quick start battery resources in line with large scale renewables in order to maintain pace with renewable goals while not sacrificing customers' access to electricity.



Source: US Energy Information Administration



Afternoon demand is lower than aggregate due to batteries being net negative. Source: CAISO Data

Natural Gas

Summary

In 2021, the dynamics in the US natural gas market shifted from low prices and oversupply to high prices and undersupply, as reflected by a 13-year high November Henry Hub price above $6.00/MMBtu. 2021 saw increased demand in commercial and industrial sectors, as well as a continuation of the reduced investment in exploration and production that followed the onset of the pandemic in 2020.

We expect domestic production to recover and domestic consumption to soften in 2022, which should put pressure on prices to decline after Q1 2022 as production begins to outpace demand.

Key Takeaways

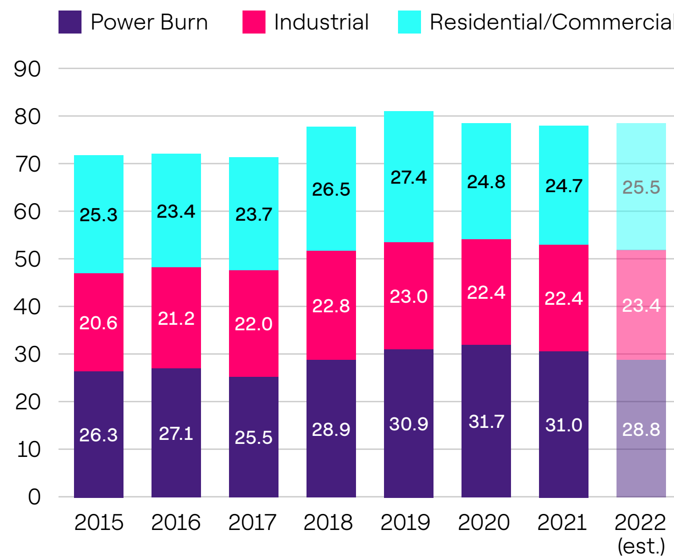
- Increased international demand, fed by an increasing liquified natural gas (LNG) export capacity, will drive upward pressure on pricing.
- Domestic supply will increase as producers commit more resources to exploration and production.
- Gas power generation will decrease due to competition with coal and increasing renewable power generation capacity.

Natural Gas Demand Forecast: Demand Will Remain Flat

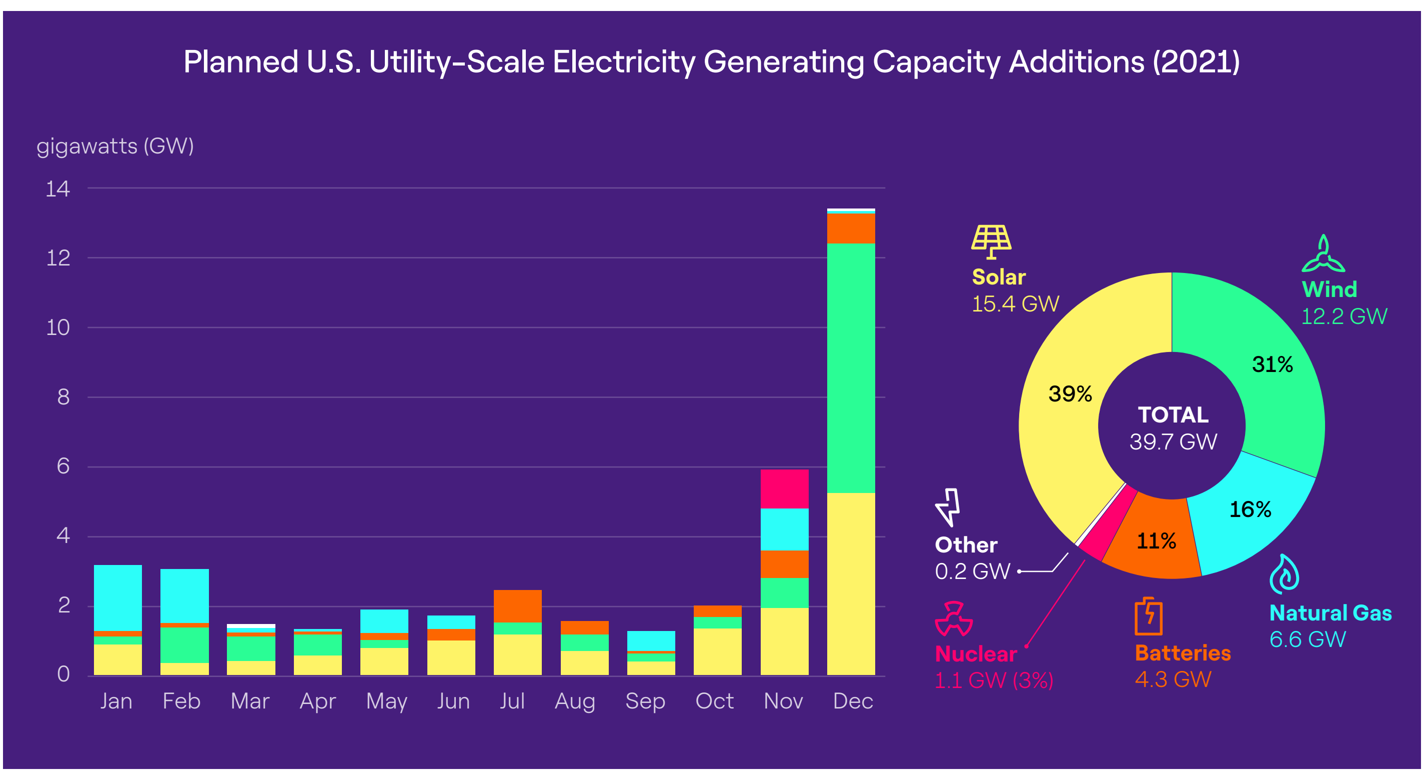
While residential, commercial, and industrial demand is expected to return to numbers closer to pre-pandemic levels, power burn demand is projected to decrease in 2022. Power generation demand for natural gas decreased in 2021 from 2020.[44] We project power generation demand to continue to decrease in 2022. Increased renewable power generation capacity across the country is part of the waning natural gas power generation demand. Over the past year, renewables outpaced gas installation 27 GW vs 6.6 GW.

However, natural gas continues to play a key role in the clean energy transition and is still the primary fuel for electricity generation across the country. This is true even in Texas and California, the leading states in renewable generation capacity. Thus, we predict the demand for gas to remain relatively consistent and do not predict a precipitous drop in demand until enough renewable generation and storage capacity come online.

Natural Gas Demand 2015-2022 (Bcf/day)



Source: US Energy Information Administration



Source: U.S. Energy Information Administration, Preliminary Monthly Electric Generator Inventory, October 2020

Pipeline and LNG Exports Will Continue to Rise into 2022

Natural gas exports remained strong in 2021, averaging approximately 16.6 Bcf/day, and will continue to increase to over 19.3 Bcf/day in 2022, likely surpassing Qatar as the largest exporter of LNG in the world. The main drivers behind the continued increase of exports are pipeline exports to Mexico and increased LNG export capacity. Pipeline exports to Mexico averaged 6.04 Bcf/ day as of November 2021.

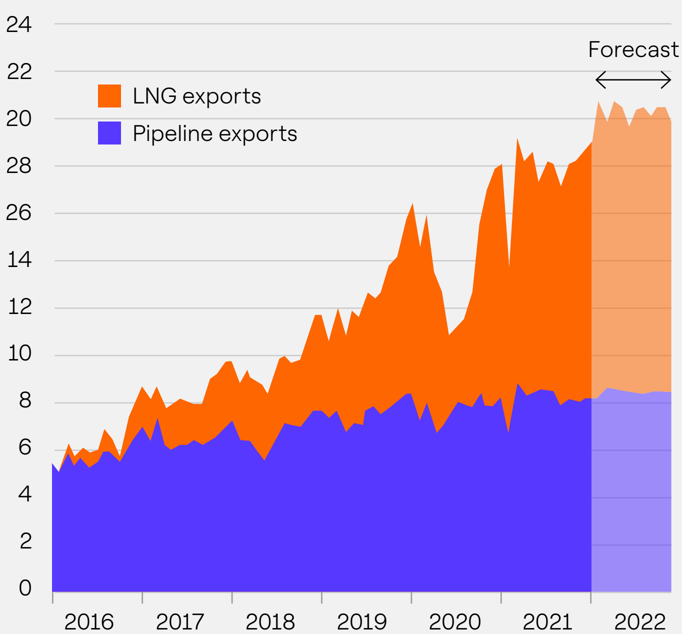
Since 2015, pipeline exports to Mexico have gone up by about 12.8% year-over-year. We expect these numbers to continue to rise as additional cross-border pipeline projects have increased pipeline export capacity, which will help supply growing industrial and power generation demand in Mexico.

LNG exports grew as additional capacity came online in 2020-2021 alongside a significant increase in global demand for LNG shipments, which caused international prices to spike while domestic prices saw less volatility. A variety of factors led to the large spread in pricing between domestic and international gas.

First, low LNG pricing and demand in 2020 caused LNG shipments to be reduced causing a lasting impact on global gas inventories. When global demand then increased in 2021, buyers were in a tight supply/demand imbalance, particularly Europe, which has high carbon pricing, essentially pricing out coal and requiring natural gas amid an abnormally warm summer with higher-than-average power generation demand. In the face of these compounding challenges, Europeans were forced to compete with Asian markets that were also responding to growth in natural gas demand, causing prices to spike to record highs.

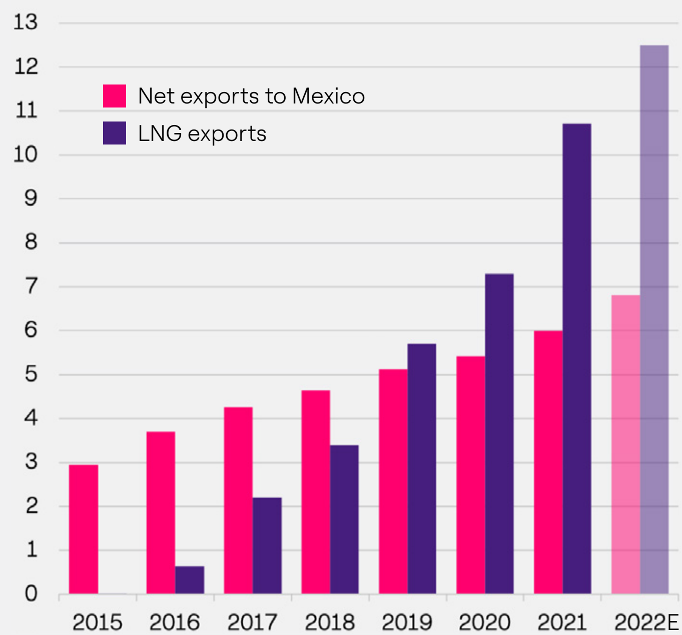
Additional LNG projects in the US can bring peak export capacity up to 13.9 Bcf/d; however, a lack of substantial additional projects internationally and the uncertainty of the Nordstream 2 pipeline in Europe leads us to predict these international prices will stay high as international demand remains elevated.

Natural Gas Exports
(Bcf/day)



Source: U.S. Energy Information Administration, STEO

Net Exports to Mexico & LNG Exports
(Bcf/day)

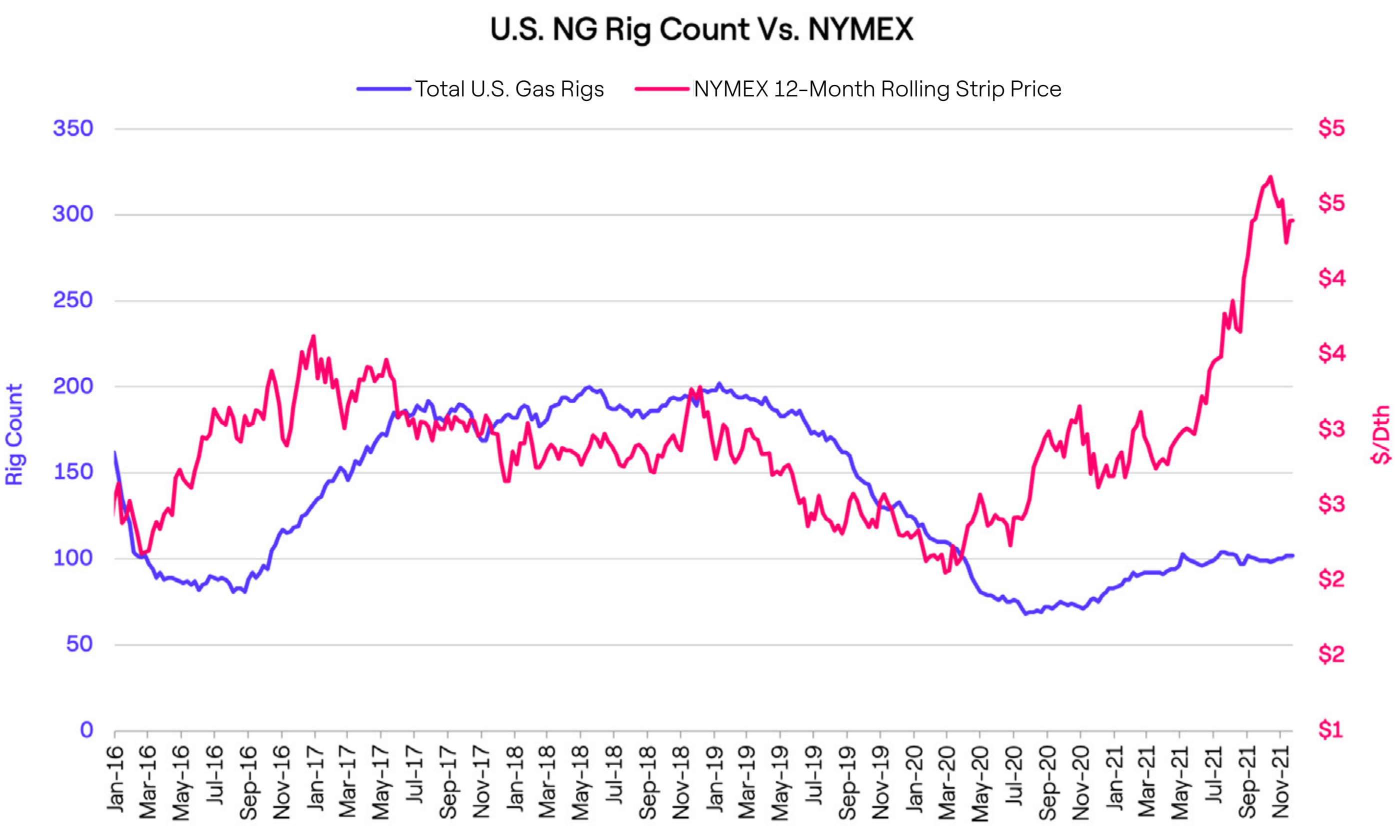


Source: S&P Global Platts

Natural Gas Supply Forecast: Declining Capex and Production

In the wake of the Covid-19 pandemic, oil and gas producers' operations were slow entering 2021. The declining pricing environment in 2020 forced producers to take impairments on long-lived assets, cut production, cut capital expenditures on exploration and production (E&P), and even in some cases declare bankruptcy. Pressure to increase shareholder value and credit worthiness resulted in stalling output, as illustrated in July 2020 when a record-low of 68 natural gas drilling rigs were active in the US (note that this data has been tracked only since 1987).

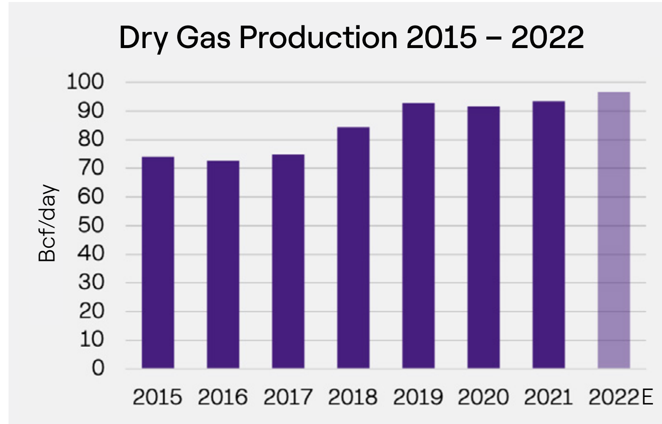
These circumstances set up a high pricing scenario in 2021 with rebounding demand and a lagging production schedule. Since August 2020, the total natural gas rig count has steadily increased. Entering 2022, there are signs of recovery with regards to production, but the fallout of 2021 still presents significant hurdles within the recovery of global markets.



Source: Rig Count from Baker Hughes; Strip Price from S&P

Production to Rebound to Record Highs in 2022

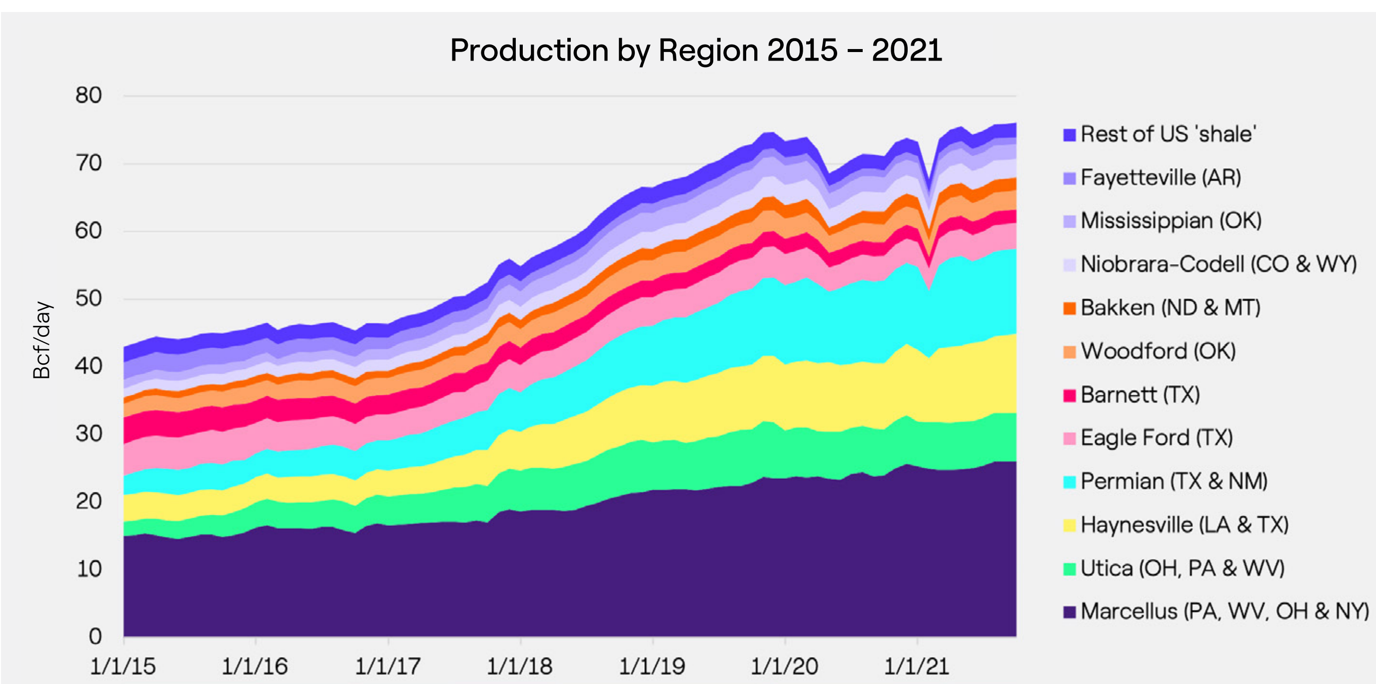
Average monthly gas production already began to recover in late 2021, and we anticipate record-high production levels in 2022 due to new production projects, already existing production, and new associated gas coming off oil wells. The lag in new production, after high prices in 2021, is due to the capital-, labor- and time-intensive process of setting up new horizontally drilled wells. The US E&P sector is projected to increase its capital spending for 2022 by 23.5% year-over-year, led primarily by private equity operations. Specifically, within the Appalachian and Haynesville basins, new production records are expected in 2022. The Haynesville region remains a strong play for its location proximity to LNG terminals, which give access to high-price international demand.



Source: US Energy Information Administration, STEO

Future of Public Equity in Natural Gas

A lagging production schedule may be the new norm for the natural gas industry after 2021 demonstrated major changes in how publicly traded producers manage their company ROI. While some companies continued to drill and create new wells, others are choosing to increase shareholder value through dividend declarations, share buybacks, and debt payments to set up favorable credit ratings. Those producers that choose to deploy assets and add rigs must do so in a much more careful manner. This is not just because of the high capital costs, but also because investors are placing greater importance on environmentally safe practices.



Source: US Energy Information Administration

PART 2

Transitioning to a Zero-Carbon Future

Summary

Climate commitments from organizations worldwide continue to drive energy markets—electric, gas, and other fuel sources—toward zero-emission sources. Companies are moving beyond renewable energy targets to set ambitious greenhouse gas (GHG) reduction targets. These targets require companies to set goals for scope 1 and 2 (and, in many scenarios, scope 3) emissions reduction, pushing companies to source renewable electricity, electrify operations, and look for other forms of low-emissions fuel or activity.

The following analysis looks at the primary energy products that organizations are using to meet emissions reduction goals.

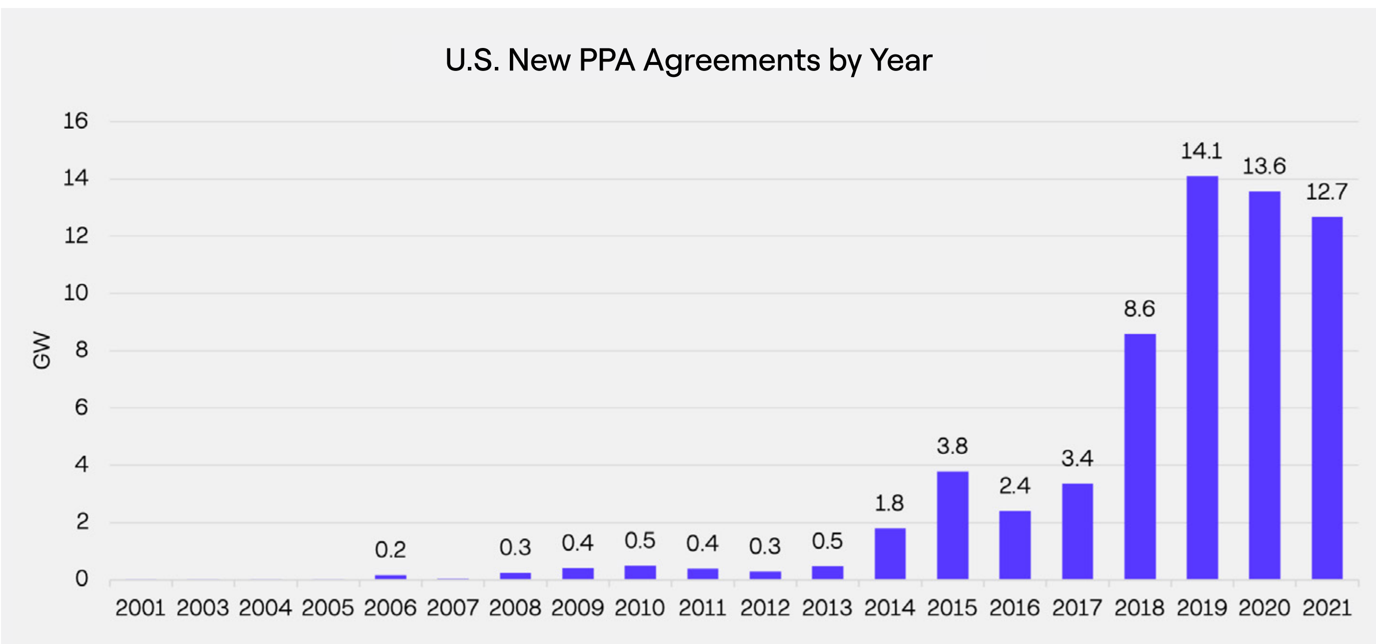
Key Takeaways

- GHG reduction targets are becoming more popular. Science Based Targets, a corporate climate action NGO, announced at COP26 that more than 1,000 companies representing $23 trillion in market cap are using 1.5°C targets.
- To achieve targets like these, most organizations require a portfolio of solutions that can vary based on regional product availability and overall objectives.
- In addition to products like PPAs, DERs, and more traditional renewable solutions, the gas market is evolving to support scope 1 emission reduction goals.

Power Purchase Agreements (PPAs)

PPAs Enable Companies to Enter the Renewable Space

The unprecedented push for green energy has undoubtedly begun in earnest and the coming years will see exponential growth as countries are increasingly designing policies to encourage investment in the sector. While some companies may look to build their own renewable installations, improve efficiencies, or amend their usage, most will find that the simplest, most effective way to procure renewable energy is through a PPA or vPPA. Corporate renewable energy purchases through PPAs and vPPAs will drive substantial growth in the renewable energy sector, incentivizing new generation projects.



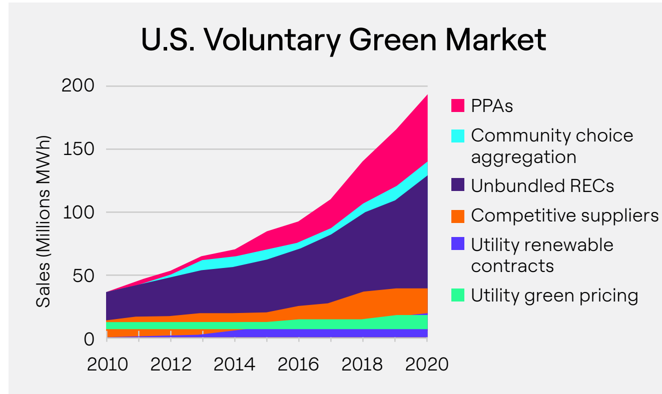
Source: BloombergNEF

Resounding PPA Growth

The prevalence of PPAs as a market share of voluntary renewables has taken off since the end of 2017 with global agreements surging from 5.6 GW to 24.3 GW by the end of 2020, with ~25 to 27 GW total expected in 2021.[45] This is expected to rise even more quickly as some formerly restrictive Asian markets (Japan, Vietnam, S. Korea) allow companies to contract PPAs with new renewable generation.

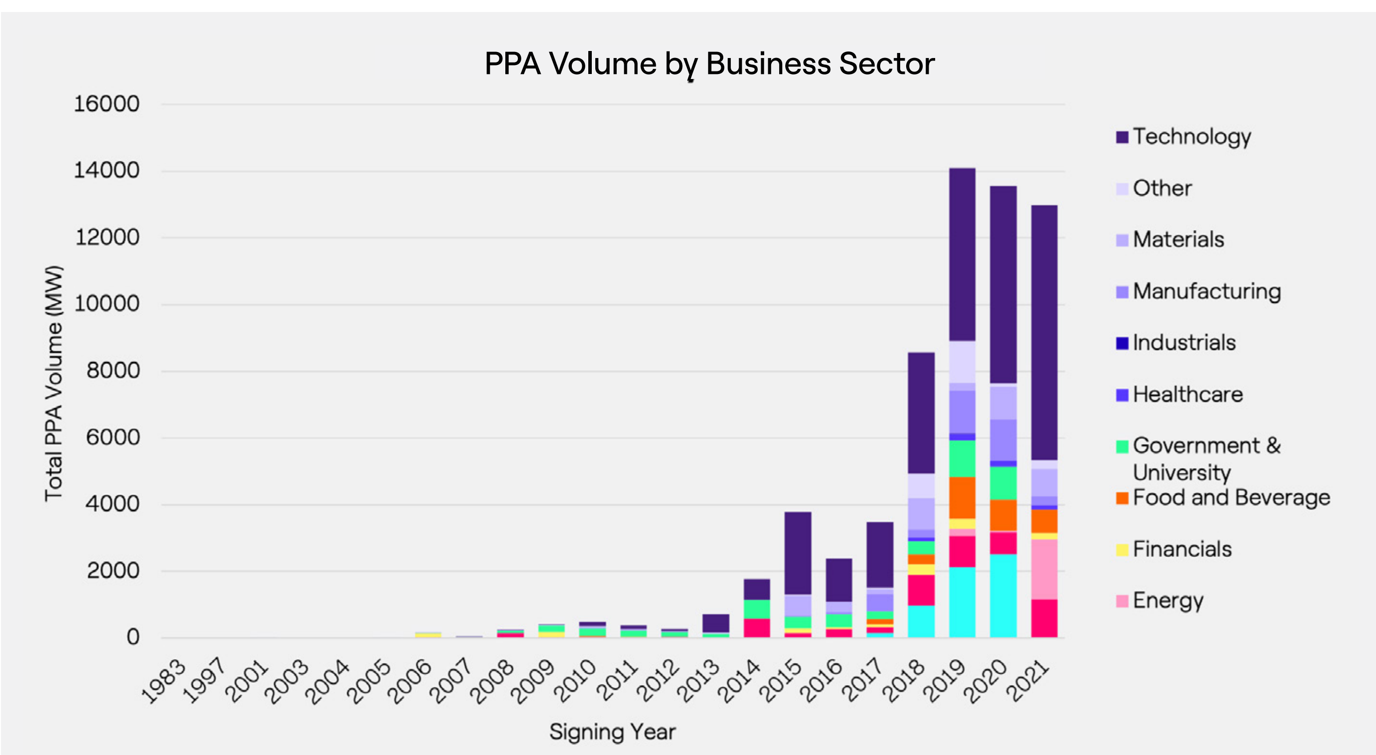
Of the 22.4 GW of global PPA contract agreements through the end of October 2021, over half the total (12.7 GW) comes from the US, with Texas atop all states in deal origination. The sheer volume of deals originating in Texas with counterparties outside of the state points to an increasing proportion of vPPAs, which are sourced from its vast portfolio of wind generation. The supply chain disruptions resulting from Covid-19 slowed down new PPA growth in 2020, but given the projection of 16 GW in the US by the end of 2021, it's clear that the demand is back on track and projected to exceed pre-pandemic 2019 numbers by end of year.

Over the last 10 years, the US voluntary green portion, defined as renewable projects or REC purchases above and beyond state-mandated RPS, of the total renewable market has risen from less than 10%, to over 35%.[46] Since 2010, favorable public policy and corporate responsibility initiatives have accelerated contracted renewable volumes in a variety of product choices. Of those products, PPAs increased their share of the voluntary green market from 4% to 27% from 2010-2020, showing that corporate and public entities see PPAs as the easiest long-term option for their newly established environmental goals. By the end of 2020 statistics showed that PPAs are now the second largest method, behind only unbundled REC purchases.



Source: Open EI, US Voluntary Green Power Market 2020

As seen in the figure below, the top offtakers by business sector offers a view into the diversity of industries participating in the renewable energy transition. The leader, by a vast margin, continues to be the technology sector with companies like Amazon, Google and Facebook entering large, long-term deals. Wireless giants such as Verizon and AT&T are responsible for the large communications sector share. Interestingly, the energy sector accounted for the second largest portion of PPA volumes in 2021. This points to the newly adopted efforts by oil and gas companies to reduce their emissions impact with PPAs; for instance, Total Group, an oil and gas exploration company, accounted for a large portion in 2021. It is clear that the PPA trend is not just relegated to one sector, and many companies see the benefits of cheap, renewable energy that allows for an easy, predictable energy budget.



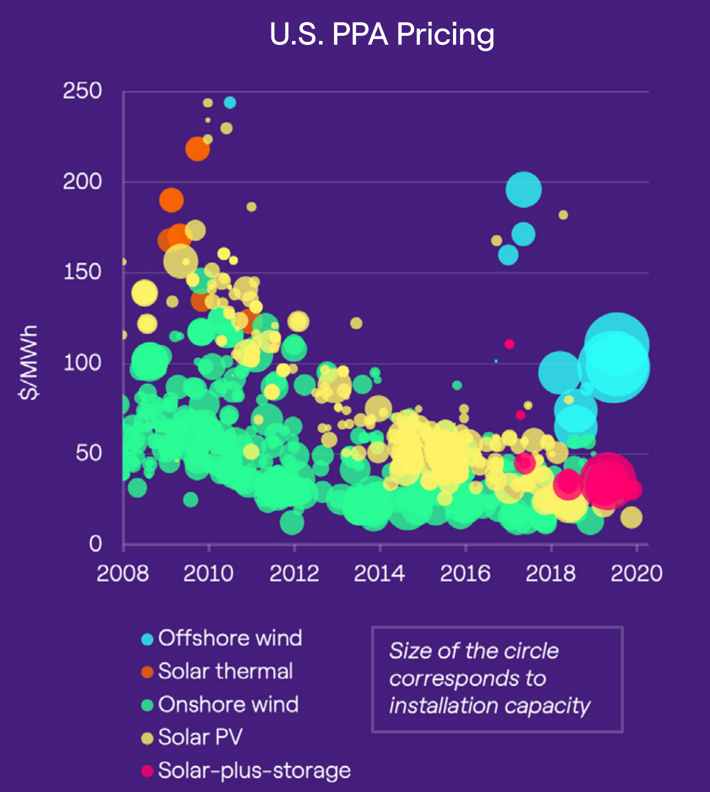
Source: BloombergNEF

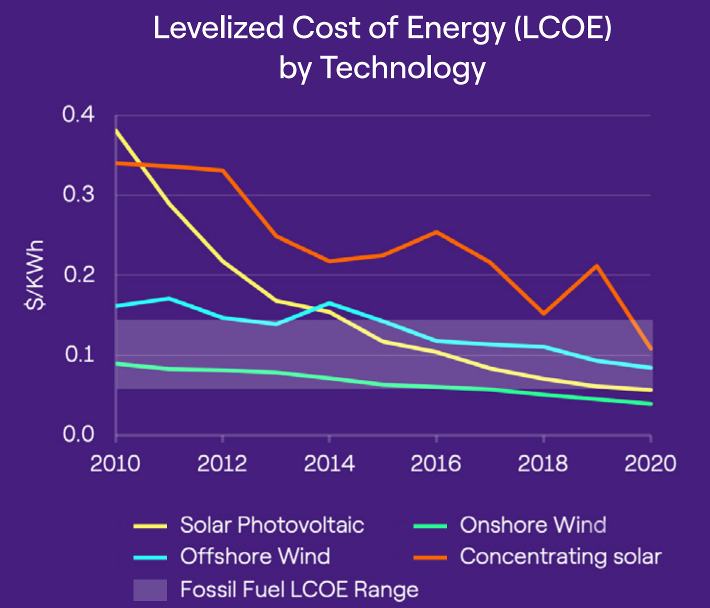
PPA Prices Continue to Become More Competitive with Traditional Brown Power Source

Average pricing for PPA contracts beginning production in 2021 was $32.88/MWh compared to an average of ~$60 for contracts starting between 2008 to 2013.[47] It is worth noting however, that pricing across regions cannot be compared, rather, a PPA price should be evaluated against recent zonal location marginal pricing (LMPs) to determine the value of the contract. For example, a PPA contract that prices power supply at $40/MWh in a market with an average price of $30/MWh for wholesale energy is much less valuable than a $70/MWh PPA in a $75/MWh wholesale market.

PPA pricing corresponds closely with the steep decline in cost per KWh of renewable technologies since 2010. Since 2015, all four major renewable technologies have been competitive with fossil fuel generation cost levels, as indicated in the bottom right figure.

Going forward, the phaseout of the Investment Tax Credit and Production Tax Credit (ITC/PTC) for solar and onshore wind in current law may put upward pressure on pricing offered in PPA agreements, though the Build Back Better Act, if passed, could contain important provisions in creating more clean energy projects.





Source: BloombergNEF

PPA Headwinds and Tailwinds

There are several developments that could decide the future of the voluntary green market, and PPAs in particular.

Tailwinds

- Exponential increase in renewable construction in the last 5 years is slated to continue with help from Biden administration initiatives in the Build Back Better Act and Infrastructure Investment and Jobs Act, creating more capacity opportunities for PPA agreements.
- There is a growing flow of private investment dollars away from fossil fuels and into renewables in the form of corporate contracts with competitive suppliers or generators.
- Increasing price of National Green-E RECs make fixed PPA prices more attractive.

Headwinds

- Supply chain constraints from Covid impacts could slow the renewable build out.
- Though the Build Back Better Act could still be passed with important clean energy provisions that would have a beneficial effect on PPAs, it currently remains stalled.

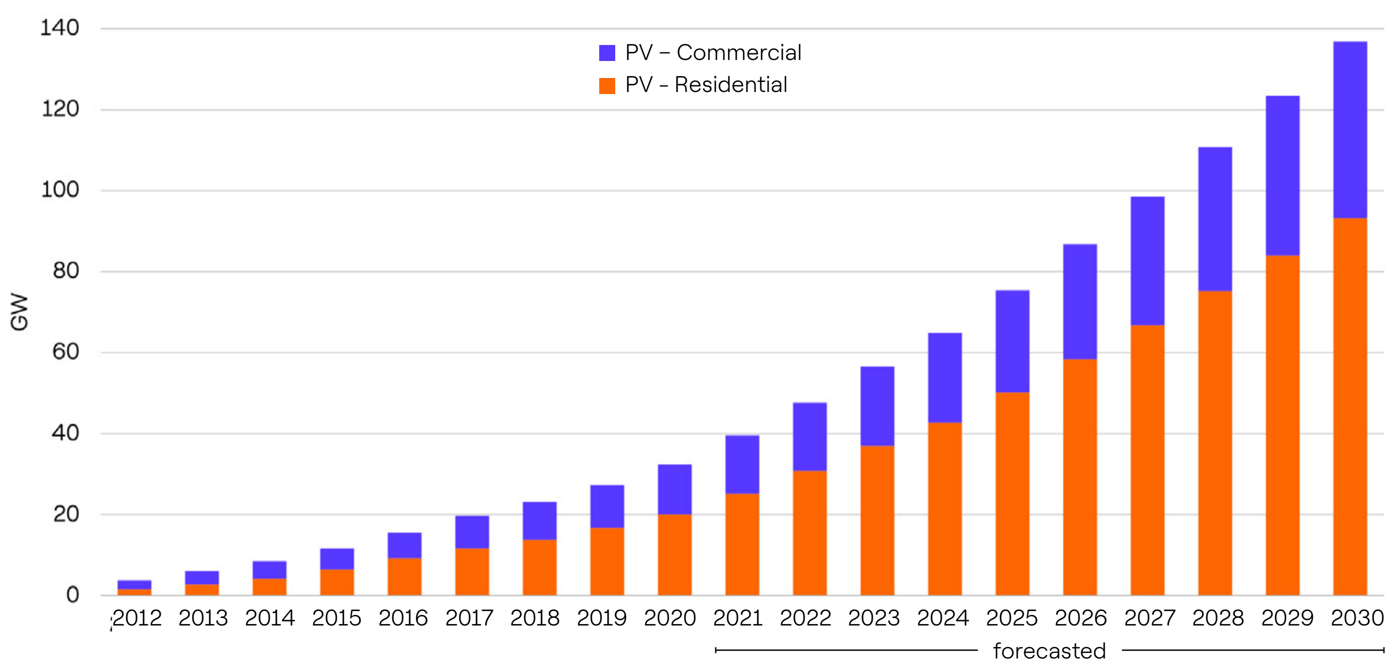
Distributed Energy Resources (DERs)

Expanding portfolios of distributed energy resources (DERs), such as behind-the-meter (BTM) solar PV, have been a key contributor to the reduction in direct power-sector emissions over the past 15 years. Corporations have been turning towards DERs to hedge against rising electricity prices and curb their own source emissions.

Behind-the-Meter Solar

DERs are power generating assets that are deployed across the grid, often behind-the-meter. They are decentralized, unlike a traditional power plant which is usually a single site (like a large natural gas or nuclear plant). This allows more businesses to take advantage of generating resources at their site. Given the falling price of solar technology and rapid adoption of behind-the-meter generation over the past 10 years, businesses are choosing to install BTM solar, as shown below. The total installed capacity of residential and commercial small solar has doubled from 2016 to 2020, going from 15.5 GW to 32 GW over four years. Projections from Bloomberg estimate the total installed capacity of small-scale solar in 2030 to be 136 GW. For context, the peak load of the PJM grid in 2021 capped out at 132 GW.

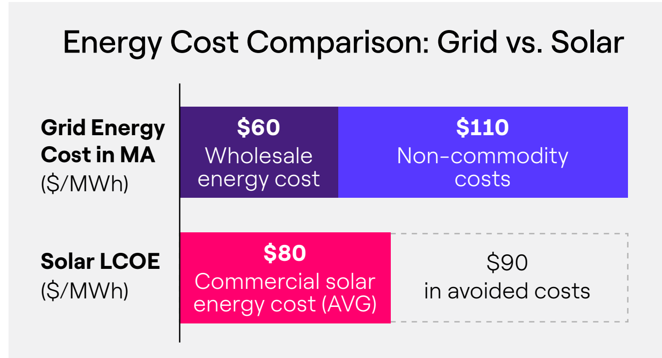
FORECAST
Solar Cumulative Capacity by Technology



Historical and projected BTM solar capacity. BTM solar has become increasingly favorable over the past 10 years—in price, availability, and support from public policy. Source: BloombergNEF.

Cost Trends in DERs

BTM solar reduces the volume of grid purchased electricity and replaces it with emissions-free energy. Roughly 25% of consumers' all-in electricity costs are for wholesale energy, the other 75% is made up of non-commodity charges such as demand, transmission, ISO and local distribution company charges. By generating and consuming electricity behind-the-meter, an organization can avoid costs that would typically be incurred at the meter. For example, the levelized cost of energy for commercial solar is around $80/MWh whereas the all-in cost for a Massachusetts customer is closer to $170/MWh depending on the utility rate class. This leads to about $90/MWh in avoided grid costs. Consumers may also be compensated for surplus power exported to the grid, depending on the state and local policy.

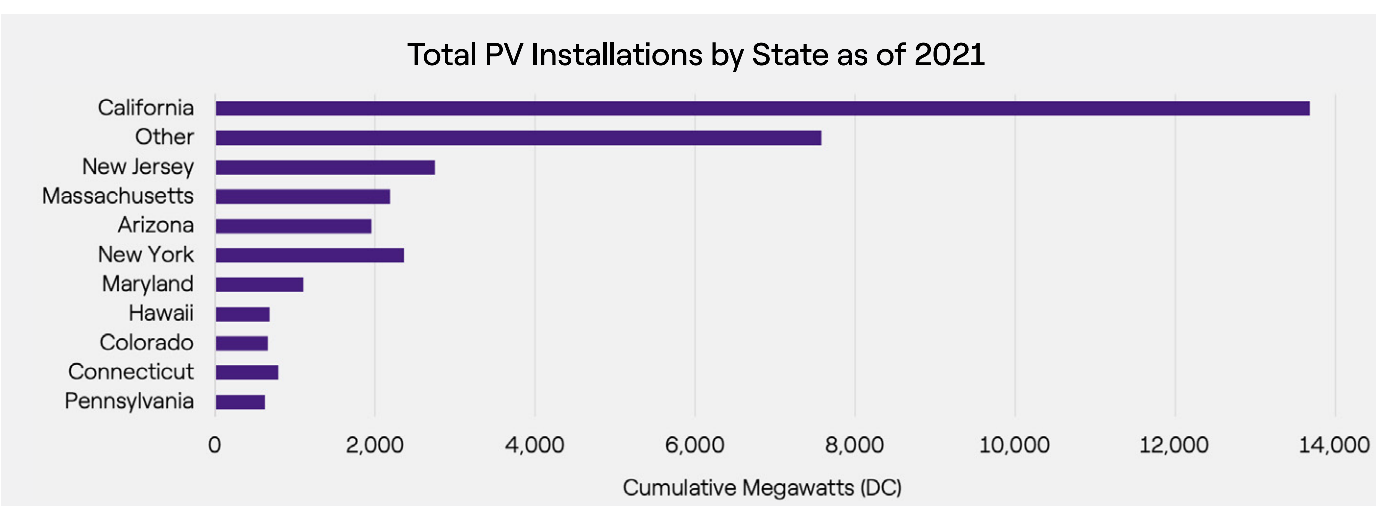


Solar LCOE is national average; LCOE for MA is likely $10-$20/MWh higher. Source: National data is from National Renewable Energy Laboratory; MA data is internal calculation by Enel X.

State programs and incentives have driven much, but not all, of the growth in behind-the-meter installations. As of 2021 all fifty states and Washington, D.C. have some form of solar incentives, though the structure of the program varies significantly by state.[48] California has the highest adoption of small-scale solar, due to ambitious legislation and ideal weather conditions.

While the Northeast does not have ideal weather conditions for solar, state incentives have nonetheless made solar economically viable in those states. For example, Massachusetts has ambitious state-led incentive programs and currently ranks third in the country for installed small-scale solar as shown below. Under the SMART program, the latest solar incentive program in Massachusetts, consumers can receive solar incentive payments as high as $0.08/kWh depending on the type of project.

One overarching policy available regardless of state is the federal investment tax credit for solar—which allows 26% of capital investments in solar to be recouped as a tax credit. The ITC was extended in 2021, and will be held at 26% through the end of 2022 before dropping to 22% in 2023. Taking advantage of both federal and local incentives allows companies to lower their all-in solar costs while also lowering their emissions.



Total small scale PV installations by state. "Other" includes all other states not listed.
Source: International Renewable Energy Agency.

The Growing Appeal of Solar + Storage

Battery storage paired with behind-the-meter solar can help optimize customers' demand and reduce purchasing grid electricity during expensive hours. Battery storage is a rapidly growing product in the DER space, with over 3.2 GW of battery storage currently operating in front of the meter and another 13.5 GW currently planned. Pairing BTM solar with battery adds reliability to a facility with the potential to run critical systems in the event of a grid outage. For example, a battery storage system at a hospital could keep -70C freezers running, preserving samples and medicine if power flow from the grid is interrupted. There is even the potential to island from the grid if the battery storage system is large enough and connected to a microgrid.

When interconnected, battery storage systems turn solar from an intermittent generating asset to a traditional on-demand asset with a dispatch period of typically a few minutes to a few hours. A battery storage system charged up with solar energy can dispatch at-will to help facilities avoid expensive demand charges. Battery storage paired with BTM solar can provide curtailment during expensive hours, but also curtailment during the critical peak hours—for example, dispatching the battery during the ICAP window if you are in ISO-NE, NYISO, PJM (multiple hours), IEOSO (multiple hours), or CAISO (depends on supplier and location). A 1 MW reduction in capacity tag from a battery storage system would save a customer in COMED about $80,000 per year if the battery hit all of the 2020 peak hours. Battery storage systems add value to BTM solar and give customers more control over their electricity costs.

Renewable Energy Certificates (RECs)

The voluntary and compliance REC markets will continue to drive the generation of renewable resources through 2022. As RPS mandates increase year-over-year and organizations continue their efforts to reduce emissions through products with greater additionality, regulatory compliance demand for RECs will likely become significantly higher compared to voluntary demand.

An Overview of REC Markets

Renewable Energy Certificates (REC) purchases fall into two markets: compliance (have to) and voluntary (want to). The compliance REC market is used to meet Renewable Portfolio Standard (RPS) mandates, which are the state-level policies designed to increase the amount of renewable electricity generation. The voluntary REC market, on the other hand, is where corporate buyers transact to meet climate-related sustainability goals and go above and beyond state mandates.

The price of RECs varies by location, market (voluntary and compliance) and type (Class or Tier), as shown below:

Factors	Description
Location	The U.S. does not have a single unified REC market. Therefore, in-state requirements for renewable generation as well as variations among RPS mandates lead to a broad variability of REC prices across states. While Texas solar RECs (SRECs) trade at ~$5.00/MWh or below, NJ SRECs trade at ~$230 or higher. **Higher prices derive from strict mandates and subsequent increased competition from utilities and end-users for RECs generated in the region in order to meet requirements.**
Market	REC prices in the voluntary market are usually less expensive than in the compliance markets. **Compliance RECs** trade across states in a broad range between ~$10-200/MWh, while **voluntary RECs** trade in a narrow range between ~$1-4/MWh but are more volatile and tend to change more quickly than other RECs in other markets. Due to the cost delta between voluntary and compliance RECs, most customers do not voluntarily buy local higher quality RECs.
Type	Carve-outs and Tier I RECs are more expensive than Tier II due to the increased demand for new utility-scale solar and wind generation across states. > **Tier I / Class I:** RECs from new wind, solar and biomass facilities. > **Tier II / Class II:** Typically include existing facilities and other type of energy generation that is excluded from Tier I (i.e. waste energy, hydro) > **Carve-outs:** RPS targets reserved for specific technologies, usually solar or offshore wind.

Voluntary REC Markets

In the voluntary market, unbundled RECs currently represent the largest contribution to GHG reduction products through which organizations are meeting scope 2 objectives. Based on the latest data published by NREL, 86.4 million MWh of unbundled RECs were sold in 2020, which is more than 2.5x greater than the 31 million MWh sold in 2012.

RECs provide organizations of any size with a quick and easy way to decarbonize their electricity supply. The low level of financial risk and complexity at the time of purchase are the main drivers for the adoption of this type of green product.

Price Trends

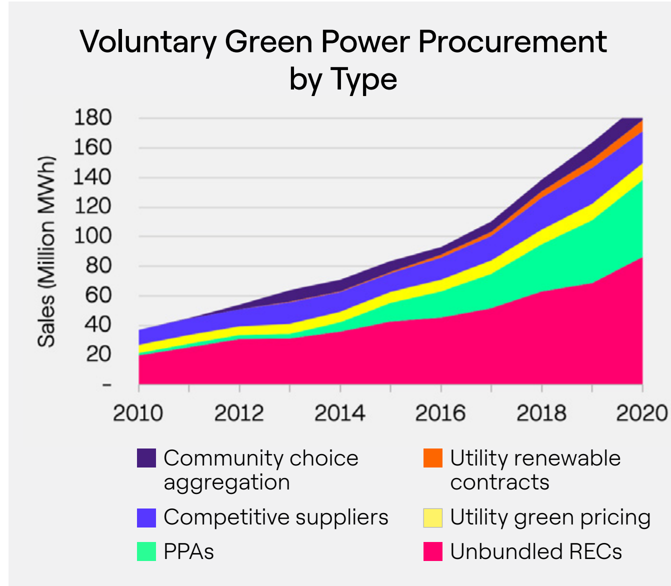
National Certified RECs usually come from the Midwest and Southern states due to the high wind and solar potential for installation in the region.[49] The chart illustrating the price for Texas Wind RECs mirrors the most recent price trends in the voluntary REC market.

For many years, the price for certifiable RECs traded in a fairly narrow range between ~$0.50–$1 as a consequence of abundant supply in the market. However, in 2021 prices spiked ~600% reaching record-highs of ~$7/MWh during the summer. As of late 2021, prices are back down trading near $4.00/MWh.

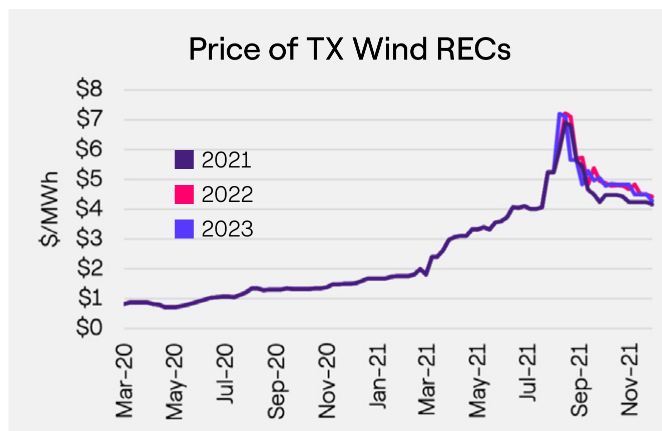
We do not anticipate unbundled REC prices to return to early-2020 levels at $1/MWh in the near future. This is primarily related to high demand coupled with tightened supply as more and more corporations look to go beyond renewable mandates. However, as more generation comes online, prices will likely fall over time bringing the long-term curve back down.

Elevated REC prices in the voluntary market might impact corporate buyers in a variety of ways. For many but not all, the increasing cost of RECs could likely incentivize buyers to adopt other means to fulfill their corporate sustainability commitments. However, the expectation of prices falling over time can also be an incentive for other organizations to stick with purchasing unbundled RECs.

A current challenge hindering the growth for unbundled RECs is the lack of additionality. Additionality is the extent to which a project adds to existing inputs resulting in a



Source: National Renewable Energy Laboratory



Source: S&P

greater aggregate. Unfortunately, the purchase of an existing resource, like RECs from an already-up-and-running wind farm, has little to no effect in the overall transformation of the grid and cannot be considered additional.

As organizations begin to embrace the value for additionality and attempt to avoid potential reputational risk, we anticipate the consideration and adoption for alternative green products, such as PPAs, to grow. Having a clear corporate purpose as to "why renewables?" is key to identifying the product strategies that best fit your organization. For 2022 and beyond, we recommend corporate buyers assess unbundled RECs as complementary products in their overall sustainability strategies, not primary ones.

Utility Green Tariffs

Though much of the focus of the green energy transition is on products in the competitive marketplace, such as corporate purchases of PPAs, RECs or on-site generation, regulated utilities offer another avenue to achieve renewable goals through green tariffs. Utilities often have specific tariffs or riders that allow customers to opt-in to utility sponsored offerings that can range from REC purchases to direct contracting with renewable generation.

Often a green tariff is the easiest avenue for a customer to purchase renewable power, though it may not always be the most cost effective or environmentally impactful. Many utilities in both regulated and deregulated states offer green tariff options, though such options are not universally available. In regulated states, a green tariff may be the only option for a small customer that cannot procure its own PPA or build its own generation. In deregulated states, the utility voluntary option will typically be more expensive than third-party suppliers, who can provide RECs and market-based solutions better suited to a business. Larger credit-worthy customers can source RECs and PPAs on their own under their own terms.

Green tariffs are increasingly being added by utilities to meet customer demands and regional mandates. While these tariffs may be a simple solution to meeting corporate goals, they can vary in important ways.

Green tariffs can fall into a few categories and can vary significantly. Utilities can offer one, all, or a combination of the following types of tariff:

> **Renewable Energy Certificates** – The utility will charge an additional rate per kWh to purchase enough RECs to cover the power used by the customer. For instance, Appalachian Power offers green energy through a REC purchase program.

> **Renewable Generation** – The utility will direct power from utility owned renewable resources within its fleet to serve the customer's load. Tennessee Valley Authority is an example of a utility that offers this option.

> **Sleeved PPAs** – Customers volunteer to purchase power from part, or all, of a PPA negotiated by the utility. The Georgia Electric Membership Corporation offers an extensive program procuring energy from a number of sources via sleeved PPAs.

Tariff Types	Pros	Cons
RECs	> Easy > Flexible volumes may be offered	> Cost – usually above market
Renewable Generation	> May meet renewable and/or carbon goals	> Reputational Risk: May include resources that do not count towards goals (e.g., Biomass) > Commitment - May require purchasing power for a minimum term
Utility Negotiated PPAs	> Minimize reputational risk by a direct purchase from a renewable resource > Offer purchasing power by allowing customers that may not otherwise qualify due to size or credit to participate in a PPA	> Can be a large commitment, with a minimum term or volume > Significant unknowns, as PPAs are negotiated by the utility. May not be in the customer's best interest and may fall through > Timing risk arising from unknown project delivery dates

A green tariff should be analyzed like a supply contract. Customers need to be conscious of the cost and reputational considerations of a green tariff. Some tariffs are simply add-ons to an existing tariff while others will fundamentally change the structure of the rate calculations. Furthermore, a customer will need to verify how their account is credited for the green power being purchased. If the utility does not have a mechanism to transfer RECs or other energy attribute certificates to the customer, the power may not count towards a customer's renewable and carbon goals.

Cost to customers for these programs, along with the structure and effectiveness, vary by state. In comparison, REC purchases are traditionally cheaper, with national Green-E RECs trading in the $4-7/MWh ($.004-.007/kWh) range, even after a volatile year, and these purchases can be done in a more customized manner with a clearer result. The table to the right shows states currently offering some form of green tariff, and a range for participation cost.

State	¢/Kwh Range	State	¢/Kwh Range
AL	2-3	MT	1-2
AK	Unspecified	NE	Unspecified
AZ	1-2	NV	1-2
CA	2-3	NM	2-3
CO	1-2	NC	1-2
FL	2-3	ND	2-3
GA	1-2	OH	0-2
HI	Unspecified	OK	0-2
ID	1-2	OR	1-2
IL	1-2	SC	2-3
IN	0-2	TN	2-2
IA	1-2	TX	Unspecified
KS	0-2	UT	1-2
KY	1-2	VT	Unspecified
MA	2-3	VA	1-2
MI	2-2	WA	1-2
MN	0-2	WI	1-2
MS	2-3	WV	1-2
MO	2-3	WY	3-4

Source: National Renewable Energy Laboratory

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Carbon Offsets: Market Reaches All Time High

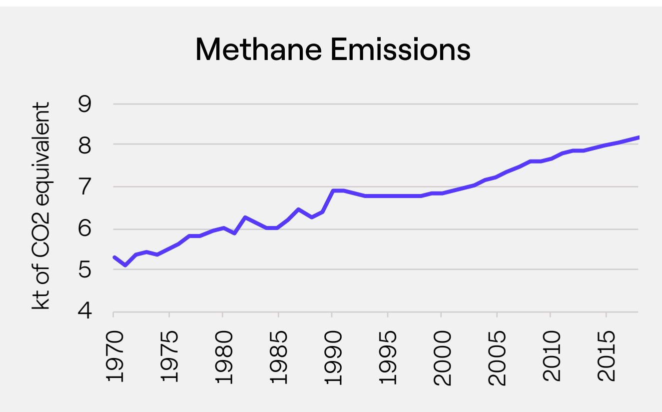
Net-zero commitments have also driven up demand for voluntary carbon credits. Carbon offsets are similar instruments to RECs, allowing companies to compensate for their emissions instead of reducing their emissions through investment in carbon reduction activity (e.g. reforestation projects). As of August 2021, the market for carbon offsets was nearly $750 million—on track for the highest annual volume to date.[50]

While the price of carbon offsets can vary widely depending on type of project and standard, the global average offset price through August 2021 was $3.13 per ton (MtCO2e), compared to $2.51 in 2020.[51] However, citing significant global increase in demand and supply limitations, a report published by Trove Research and University College London (UCL)[52] forecast prices could increase anywhere up to $20-$50 per ton.

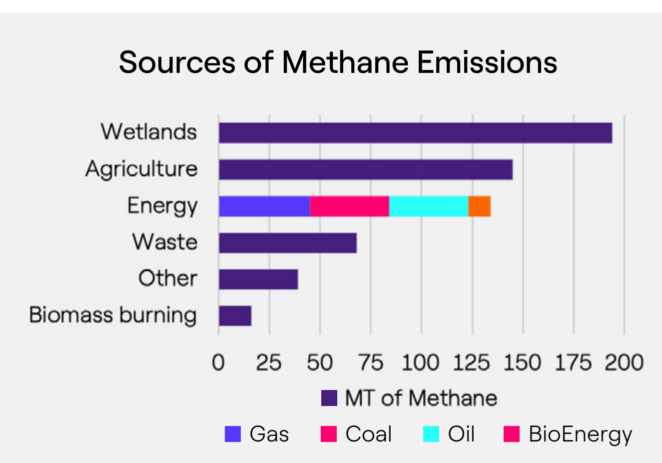
Renewable Natural Gas (RNG)

Renewable natural gas (RNG) offers a strategy to capture and utilize methane leaks from large scale human activity such as landfills, livestock operations, and water treatment plants.

Methane already comprises about 20% of global emissions and is more than 25 times more potent in trapping heat within the atmosphere than carbon dioxide. Additionally, the amount of methane emitted into the atmosphere has trended higher year-over-year since 1970. The primary anthropogenic drivers of methane emissions are energy and agriculture.



Source: World Bank data



Source: World Bank data

The oil and gas industry is attempting to address methane emissions with products such as RNG. RNG addresses agricultural methane emissions, decreases carbon footprints, utilizes existing pipeline infrastructure, and increases farmers' revenue. If all natural gas in the US was RNG, there would be no carbon emissions from fossil fuel gas sources, and the resulting scope 1 emissions for organizations burning RNG would be zero.

Currently there are four main sources of biogas used to produce RNG in the US: municipal solid waste landfills, waste water recovery facilities, livestock farms, and stand-alone organic waste management operations. RNG is created through the anaerobic digestion of these products as microorganisms break down these materials in the absence of oxygen.

More companies and institutions are beginning to recognize RNG for both its significant potential as a resource and its potential contributions to a greenhouse gas emission reduction strategy. In California alone, there is expected to be over $1 billion invested in RNG development by 2024 through both public and private funding, which is projected to create 160 new RNG production facilities. Over 130 of these facilities will be agricultural RNG projects. In the eastern United States, Eastern Gas Transmission (formerly Dominion) has partnered with other stakeholders, including a variety of agricultural institutions, to commit $900 million in developing RNG projects.

RNG derived from livestock feed is the most desired because this RNG yields a very low carbon intensity (CI) as compared to other fuels. Carbon intensity represents the amount of carbon by weight emitted per unit of energy consumed. The lower the carbon intensity, the better, because this means a greater reduction in carbon emissions. The ultralow CI is possible because manure and animal waste is diverted from lagoons that would otherwise emit methane to the atmosphere. Accounting for the prevented methane emissions allows the fuel to achieve a negative CI value.

Reliably Sourced Natural Gas (RSG)

In 2021, several of the largest natural gas producers in the US, including some midstream companies, announced they would be entering into an agreement with third parties to ensure their production and gas flow is free from methane leaks, from upstream to downstream, which spawned a new product called Reliably Sourced Natural Gas (RSG).

The product is still evolving in how it will look and trade, but we project RSG to become a key point of interest within the industry for many natural gas producers and midstream operators, especially if large downstream end-users, such as utilities, or states begin to require this product. Production of RSG may be an avenue for natural gas producers to gain more favorable credit ratings in the long term.

Hydrogen

Hydrogen holds great potential in helping to reduce GHG emissions, but its promise is contingent on how it is formed.

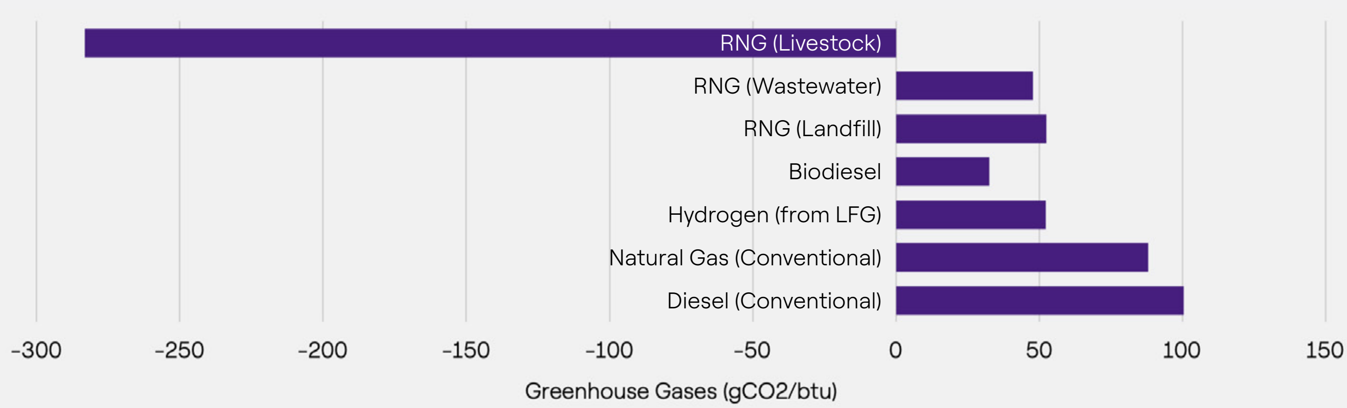
Hydrogen formation is possible through a variety of means including coal gasification, steam reforming of natural gas, pyrolysis of natural gas, and electrolysis to split hydrogen from water molecules. When derived using renewable energy, this is called “Green Hydrogen,” which holds the most potential to help achieve emissions goals. It may also help to solve a long-term storage related issue with renewables by diverting excess power from renewables (when not needed on the power grid) to an electrolysis system which can remove and store the hydrogen. This can offer a greater storage capability and a larger power capacity than lithium-ion batteries.

There has long been major potential and excitement around hydrogen, and in recent years many have thought hydrogen was closer than ever to fulfilling that promise. However, there are still barriers in terms of high costs associated with “Green Hydrogen” production, and widespread use will require overhauling existing transportation infrastructure to allow for a larger scale of applications.

Different Shades of Hydrogen

Green *Zero Carbon*	Electricity from renewable sources is used to separate hydrogen from oxygen in water molecules through process of electrolysis.
Blue *Low Carbon*	Natural gas is used to produce hydrogen through process of “steam reformation,” where most of the greenhouse gas emissions are captured and stored.
Turquoise *Low Carbon*	Natural gas is used to separate methane into hydrogen and solid carbon dioxide through process of pyrolysis.
Grey *High Carbon*	Natural gas is used to produce hydrogen through process of “steam reformation,” where no carbon or greenhouse gases are captured in the process. (One of the cheapest ways to make hydrogen.)
Brown *High Carbon*	Produced using coal instead of natural gas, and no carbon or greenhouse gases are captured. (One of the most abundant forms of hydrogen currently available.)

Carbon Intensity of Transportation Fuels (in California)



Source: Gladstein, “An Assessment: California’s In-State RNG Supply for Transportation 2020 -2024”

PART 3

Regional Energy Market Outlooks

California

Summary

Following the incidence of rolling blackouts in 2020, California's grid entered 2021 with band-aids of regulation and growing anxiety that the grid would once again fail to meet consumer needs. While the failures of 2020 did not materialize again this past year, early calls to reduce usage from the state's grid operator and the worsening drought in the West only affirmed that the grid continues to stand precariously.

2022 presents similar themes to the year prior, as expectations of additional generating capacity are mitigated by reduced output of hydro resources, increased competition for natural gas, and rising utility costs amid climbing energy prices nationally. This year offers the state an opportunity to reduce grid reliability concerns, though it will ultimately come at a cost to ratepayers.

Key Takeaways

- Generation shortfalls amid the hottest summer on record[53] and drought conditions pushed regional electricity and natural gas prices to the highest levels of the past decade.
- While energy prices have fallen since their peak in October 2021, most customers can expect to see rising costs in 2022.
- A projected 5,000 MW capacity shortfall in 2022 indicates consumers are still vulnerable to emergency calls to curtail usage and potential blackouts.
- New procurements approved by state regulators will provide increased grid reliability in the long term and maintain pace with the state's renewable goals, though short-term additions have done little to assuage concerns for 2022.

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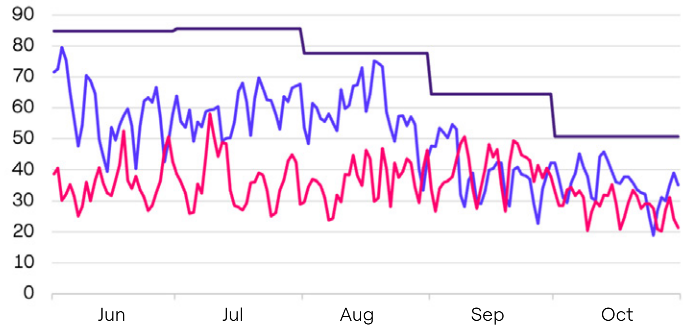
Drought Forcing Hydro Generation Reduction

Entering 2021, California's reservoirs were roughly 20% below the 50-year average. Drought conditions continued to worsen due to a dry winter resulting in below-average snow pack entering the summer peak demand season. While historically the state's grid operator has leaned on hydro generators to provide consistent capacity to consumers, CAISO opted to rely heavily on natural gas fired generators early in the summer to preserve hydro availability through the rest of 2021. The lack of steady hydro generation in conjunction with an early summer heatwave throughout the west resulted in the highest monthly average spot price for the month of June and calls from the state grid operator to reduce electric usage in order to avoid rolling blackouts.[54]

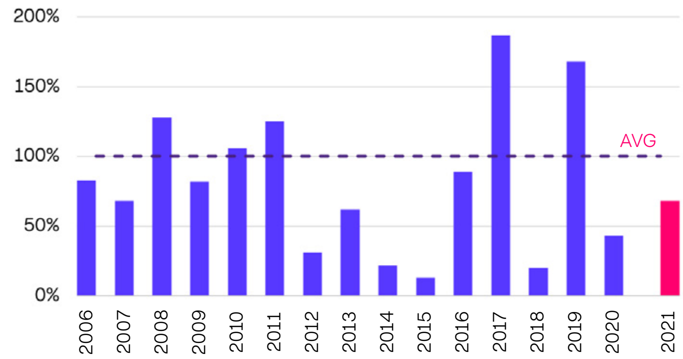
As of December of 2021, California's reservoir levels are roughly 40% below the 50-year average. Drought conditions are expected to persist as precipitation forecasts for the state are trending towards below average snow and rain through this winter.[55] In 2021 hydro averaged just 5% of generation within CAISO compared to 12% in the five years prior. Without consistent availability of large hydro, consumers will likely see decreased grid reliability and greater volatility in wholesale electric markets.

California's Daly Hydro Generation (GWh)



Source: S&P Platts Megawatt Daily Fundamentals Data

Snowpack Percent of Historical AVG for Mar 1



Source: California Department of Water Resources

Shasta Dam

Natural Gas Availability Concerns Grow

Record high prices in the region and growing concerns surrounding gas availability for the 2021/22 winter pushed regulators to increase the cap on gas storage at the state's largest (and most controversial) gas storage facility, Aliso Canyon. The added 7 Bcf of storage capacity has pushed forward basis pricing down below $0.50/Dth for the first time since February 2021. The increased limit is only approved for the 21/22 winter season and the facility will still be subject to withdrawal limits, ultimately making it a band-aid for gas availability concerns that are likely to persist through 2022 driving greater volatility on gas prices in the region.[56]

2022 Generation Outlook

This past July, California Governor Gavin Newsom signed an emergency proclamation instructing state energy regulatory agencies to "work with the State's load serving entities on accelerating plans for the construction, procurement, and rapid deployment of new clean energy and storage projects to mitigate the risk of capacity shortages." While rolling blackouts did not occur in 2021, the Governor projected a 5,000 MW generation shortfall for 2022, which could result in forced service interruptions if regional heat storms return this summer.[57]

Amidst high grid reliability concern, the California Public Utilities Commission (CPUC) approved a procurement order for 11.5 GW of new clean energy resources by 2026. The order requires load servings entities to procure 2 GW of new capacity by 2023 and an additional 6 GW the following year.[58]

The added resources will be critical in offsetting the closure of more than 3 GW of natural gas power plant capacity originally slated for retirement in 2020, now extended into 2023, and Diablo Canyon, the state's last nuclear power plant, in 2025. Other efforts could help, as well—an offshore wind bill that passed last year would encourage development of up to 10 GW by 2035, and some of that generation will be near the retiring Diablo Canyon facility.

Retail Price Trend

Both customers on utility generation service and those on Direct Access (DA) who entered into new supply agreements in 2021 likely paid more for electricity in 2021 due to climbing wholesale electric costs. These climbing costs are a result of increased natural gas prices both regionally and nationwide.

This year, customers receiving utility generation should expect to see rates continue to increase due to utility rate adjustments lagging the forward wholesale market. Customers who are in the Direct Access program with upcoming procurements in 2022 may see opportunities to place hedges below the peak prices of 2021 though they will still see increased costs compared to the past five years. Those who have previously applied for Direct Access should carefully consider the opportunity if selected as the CPUC recommended to halt future program load expansions.[59]

Customers should be aware of rising costs for Resource Adequacy (RA) in 2022. The RA ensures that all load serving entities have contracted for adequate generation to meet their customer demand. Due to the growth in generation constraints over the past five years, RA costs have substantially increased, ultimately driving up costs for customers. Due to the forecasted generation shortfall in 2022, RA costs are expected to increase again for customers with upcoming procurements.

Renewables

In 2020, California achieved its initial goal to have 33% of electric sales come from renewable resources. The next step is 60% by 2030, followed by the final goal of 100% by 2045. While the CPUC's latest report signals that retail electric providers are on pace to meet state requirements, the forecasted RPS percentage of 27% for Electric Service Providers in 2021 indicates that third party suppliers will have to procure more renewable resources in the short term to catch up. Given the constraint on available generating resources, this will put upward pressure on state REC prices in the short term, potentially increasing costs for consumers.

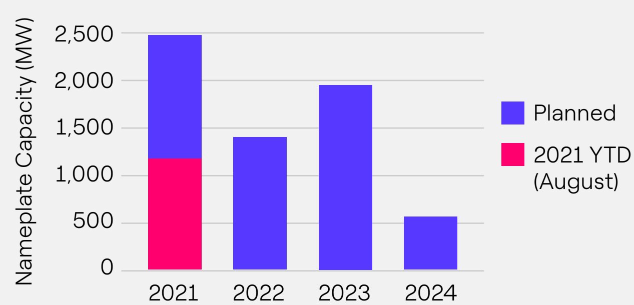
According to the EIA, California's grid will have added roughly 2 GW of new renewable capacity in 2021, with more than 6.5 GW more slated to come online in 2023 and 2024. In addition to renewable generators, the state added a record amount of battery storage in 2021 at roughly 2.5 GW with a projected 1.4 GW to be added next year. Expediting battery additions to the grid will be critical for consumers as they will be largely responsible for increasing grid reliability without compromising the state's renewable goals. In 2021, the CA Legislature passed a bill with the goal of developing 30 GW of offshore wind by 2030 and 110 GW by 2050.

Aggregated Actual and Forecasted RPS Percentages

	2018	2019	2020	2021
Investor-Owned Utilities	38%	35%	35%	47%
Small and Multi-Jurisdictional Utilities	23%	23%	46%	37%
Community Choice Aggregators	50%	55%	47%	46%
Electric Service Providers	41%	43%	37%	27%

Source: CPUC, "2021 California Renewables Portfolio Standard"

California Grid Battery Additions



Source: US Energy Information Administration

Texas

Summary

Texas is an "electrical island" that generates and supplies all of its own electricity. In February 2021, Winter Storm Uri, an unprecedented winter weather event, caused a massive power generation failure across the state, leaving millions of households without electricity in times of peak demand. The Texas power crisis in 2021 raised concerns about ERCOT's grid reliability and led state regulators to implement new legislation. In 2022, ERCOT will continue its efforts to redesign the power market in response to the blackouts. In addition, utility-scale solar capacity will continue to grow in the region as a complementary resource for wind.

Key Takeaways

> In the aftermath of Winter Storm Uri, Texas adopted new legislation that will prompt significant changes for the power market in the years ahead.

> ERCOT's efforts to make the grid more reliable will continue beyond 2022. Uncertainty around extreme weather events and a potential surge in demand in a region of robust economic growth are the main drivers leading ERCOT to adopt new measures.

> In 2022-2023, we expect Texas to keep setting records for installations of utility-scale solar capacity, as a result of decreasing costs and suitable conditions for renewables in the region.

> While still unpassed, if the Build Back Better Act is able to pass with its current clean energy provisions intact, the option to select PTC for solar will have big effects in ERCOT.

ERCOT Continues Efforts to Improve Grid Reliability

During the extreme winter event in 2021, the ERCOT grid was incapable of meeting demand for power with additional generation. The chart below illustrates the impact of below-freezing temperatures on the demand and supply for power in Texas.

The average daily temperature in the region started to decline on February 7th and remained at below-freezing levels until February 19th. Between February 7th and 13th, the average hourly demand for electricity in ERCOT increased 51% from 39,079 MW to 59,134 MW. In the same week, unplanned outages in generating units resulted primarily from freezing issues and fuel shortages. Coal, nuclear and natural gas plants shut down because of frozen equipment and/or natural gas constraints, while wind went offline due to turbine blade icing.

Although all sources struggled to generate power during the winter event, intermittent renewable energy was not the primary cause for the blackouts, as some falsely claimed in early 2021. In fact, ERCOT projected in its Seasonal Assessment for Resource Adequacy (SARA) that 80% or 67 GW of the grid's winter capacity could be generated by thermal resources.

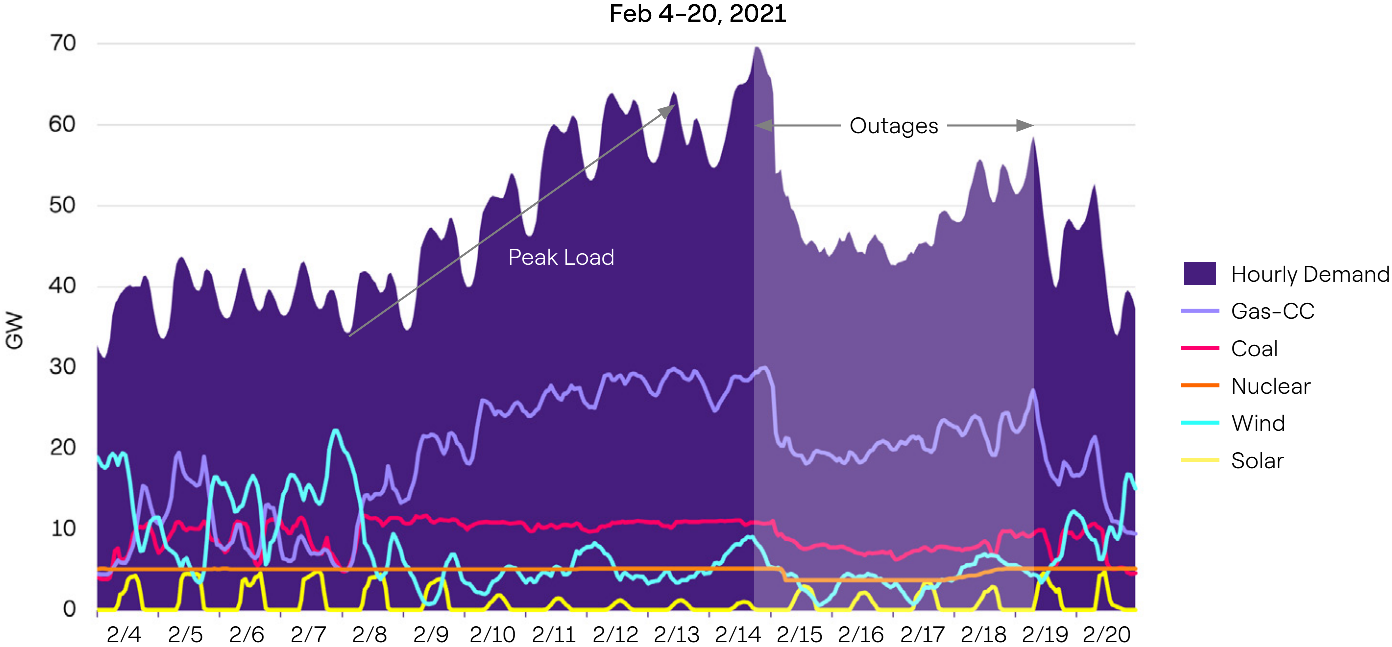
On February 14th, demand reached its all-time high winter peak of 69 GW, while natural gas production and power generation continued to worsen. Between February 15th and 17th, ERCOT averaged ~34 GW of unavailable generation. To balance demand with available supply, ERCOT had no choice but to reduce consumption by switching off electricity to groups of customers for three consecutive days.[60]

As a result of scarcity pricing in ERCOT, prices in the wholesale spot market traded at the $9,000 MWh cap for approximately 77 hours from Feb 15th to 19th. Ratepayers under a procurement strategy with spot market exposure faced the greatest risk.

To avoid high energy bills going forward, Texas legislators passed HB16 which prohibits wholesale indexed products for residential and small commercial customers.[61] Similarly, medium and large customers are required to acknowledge the potential effects of scarcity pricing dynamics in their bills prior to enrolling in an indexed electricity contract.

ERCOT – Hourly Generation by Fuel Type and Demand

Feb 4-20, 2021



Sources: ERCOT Fuel Mix Report 2021 & 2021; ERCOT Hourly Load Data

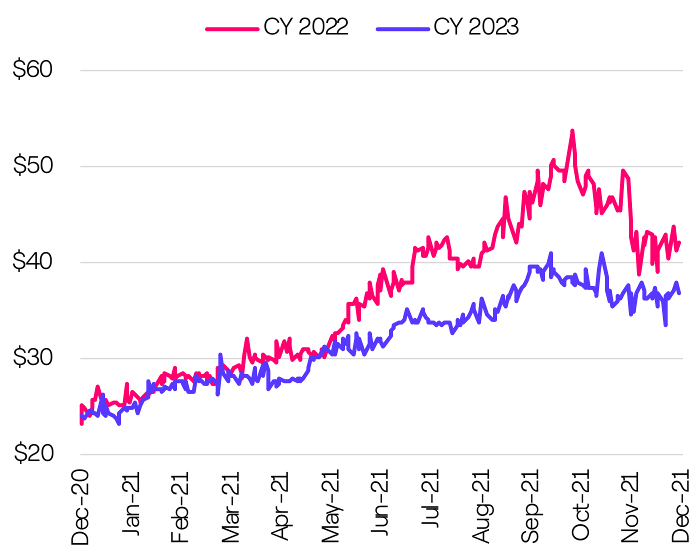
What to Expect in Winter 2022

The possibility of any further extreme cold events cannot be eliminated, even if current NOAA forecasts for this winter in Texas predict milder temperatures and drier-than-average conditions.

Efforts to ensure grid reliability will continue in 2022. By December 30, 2021, ERCOT had completed more than 300 inspections at electric generation units and will conduct follow-ups on facilities with potential issues in early 2022.[62] In addition, other new regulations will take effect: starting January 1, when energy reserves become scarce, energy prices will be capped at $5,000 MWh rather than $9,000/MWh. For ancillary services, new market rules allow additional procurement of Responsive Reserves (RRS) and Non-Spin Reserves (Non-Spin) to keep prices affordable during the winter and lessen financial risk to customers during emergencies. Customers under fixed price contracts might be subject to additional costs in invoices because of ERCOT's uplift in ancillary obligations. Lastly, ERCOT is incentivizing demand response and distributed generation programs to ensure grid reliability. Customers in these programs are compensated for reducing their load when needed.

The calendar year 2022 strip prices for North Hub almost doubled from $24/MWh in December 2020 to ~$42/MWh in December 2021 as illustrated in the chart. 2021 saw a steady increase in power prices primarily influenced by heightened volatility in the gas market. To date, natural gas remains the largest source of power generation in ERCOT representing 36% of the overall generation mix. ERCOT's dependency on natural gas highlights the urgency of winter preparedness in both natural gas and power production facilities going forward. Of particular note, the natural gas supply system has large escaped any winterizing as a result of Winter Storm Uri. As of late December 2021, CY 2023 power prices traded $4.00 below CY 2022 prices at $38/MWh. Backwardation in the market is expected to continue through 2022.

ERCOT North Hub
CY 2022-2023 Strip Prices – ATC
($/MWh)

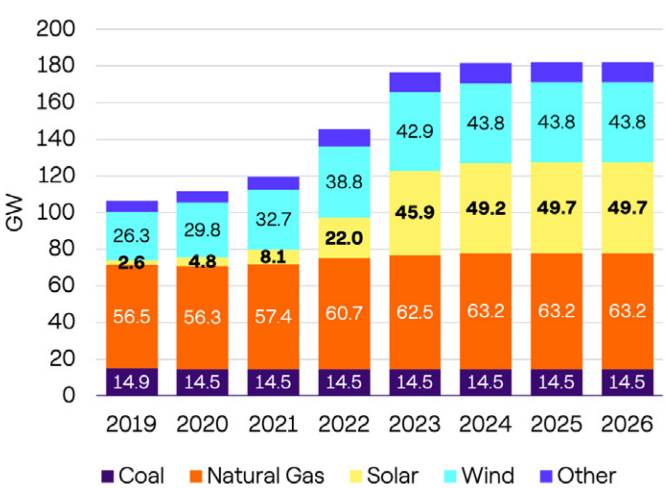


Source: S&P

Growth of Utility-Scale Solar Resources

Utility-scale solar capacity is expected to almost triple from 8 GW to 22 GW making up the largest share of the state's total additions in 2022. The projected growth for wind and solar capacity will increase considerably through 2023 and start flattening out in the years ahead. In comparison to other states, Texas' future solar capacity based on planned and under construction projects is already four times greater than California's planned capacity.

Operating and Planned Capacity in Texas



Other fuel types include Biomass, Petroleum Products, Uranium, Water, etc. Source: S&P

The factors driving the explosive growth of solar in the region include economic incentives from the federal tax credit as well as from declining costs for installation, zero-carbon technology, potential surges in demand, and suitable weather conditions in the region, especially in West Texas' Permian Basin.

After the winter emergency, multiple concerns were raised about ERCOT's preparedness for the summer. However, more generation supply, especially from solar resources, and a moderate peak demand compared to 2020 levels led to less volatile LMP prices in 2021. The systemwide price did not exceed $450MWh during July and August, compared to 2019 and 2020 where prices reached the $9,000 cap during the summer.[63] The steady power prices during summer 2021 illustrate how solar generation works well in Texas as a complementary resource for wind to help meet high demand during the day, although there are lingering concerns around Generic Transmission Constraints, which would curtail generation output, due to congestion on the transmission system.

As the generation mix continues to evolve, ERCOT is working towards adopting better forecasting resources. More accurate weather predictions may improve estimations for operational reserves during the summer and winter, reduce potential volatility in LMP pricing and ensure a more reliable grid.

New York

Summary

2021 saw major energy headlines in New York, especially New York City—average spot prices in NYC doubled in 2021 compared to 2020, driven by higher natural gas prices year-over-year. While gas fired generation is here to stay in New York for the near term, New York State still aims to hit 70% renewable electricity by 2030 and 9 GWs of offshore wind by 2035. Approximately 2.8 GWs of offshore wind procurements have been added to the queue in 2021 on top of the previously solicited ~2 GW. Increasing amounts of renewable generation on the grid will likely have downward pressure on energy prices and will introduce much needed fuel diversity. However, the potential for rising non-energy cost components associated with these projects could impact ratepayers.

Key Takeaways

> New York monthly peak demand stayed very low compared to pre-COVID levels—muted demand could have downward pressure on energy and capacity prices going forward. New York set preliminary peak hour in June 29th, 2021.

> New York selected two new offshore wind projects in 2021 in response to the most recent competitive solicitation, adding an additional 2.8GW of offshore wind to the queue.

> 2021 Zone J spot prices were on average double their values from 2020. Increasing amounts of renewables could have downward pressure on pricing long term. For now, natural gas still sets the price for NYC energy.

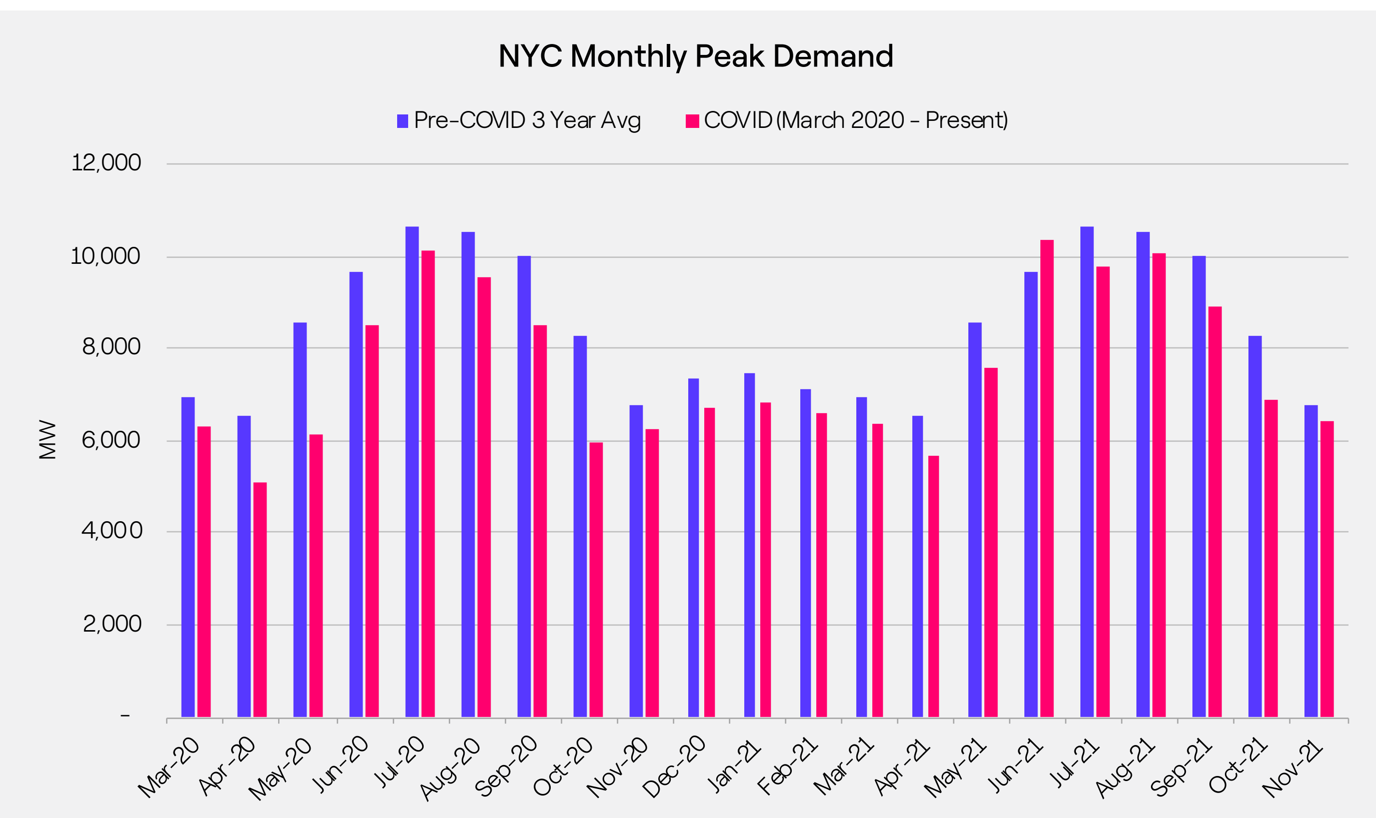
Zone J Prices and Peak Demand

Muted demand could impact the Zone J pricing environment if 2021 trends continue. NYC was unusually quiet in 2020—with the vaccine rollout in 2021 and some semblance of normalcy returning to the city, Zone J electricity demand responded accordingly.

This could leave a lasting impact on Zone J electricity costs going forward. From April 2020 through June 2020 NYC demand fell dramatically below the three-year historical baseline as shown below. For example, peak demand in April and May 2020 came in 22% and 27% lower than the historical baseline, respectively. For the one-year period between July 2020 and June 2021, the average NYC peak demand was on average 11% lower than the historical baseline.

One notable outlier is June 2021, where the peak demand came in higher than average due to the NYISO system peak which occurred on June 29th between 4:00PM and 5:00pm. The peak hour incurred additional electric cooling load on the grid when compared to previous June data. A consumer located in NYC with a 1 MW peak load contribution in summer 2021 should expect to pay about ~$50,000 in capacity costs between May 2022 and April 2023.

The trend of lower peak demand will likely continue as remote and hybrid work models become the new norm. This could have downward pressure on Zone J forward capacity prices, as less generation on average will be required to meet the monthly peak demand. Lower non-coincident peak demands have led the preliminary installed reserve margin for the 2022/23 capacity year to decrease year-over-year to 18.6%, down from 20.7% in 2021/22.[64] Looking forward, New York's shifting generation mix could also have an impact on prices in New York City.



NYC peak electricity demand by month during COVID, as compared to the pre-COVID 3-year average. Source: S&P

Offshore Wind Heats Up in New York

In order to meet the ambitious requirements set forth by the Climate Leadership and Community Protection Act, New York must move full speed ahead on offshore wind procurements. In 2021 New York selected two new offshore wind projects in response to the most recent competitive solicitation—Empire Wind 2 (1,620 MW) and Beacon Wind (1,230 MW). Additionally, in January 2022 Governor Hochul simultaneously announced a new 2,000 MW offshore wind procurement as well as a $500M investment in critical offshore wind infrastructure. These projects will help New York advance towards its goal of reaching 9,000 MW of installed offshore wind capacity by 2035. Current projects are shown in the table below. The two projects that came out of the 2018 solicitation, the Empire Wind and Sunrise Wind projects, have a projected OREC cost of $25.14/MWh.[65] Compare this to 2021 NY Tier I REC prices, which traded between $21-$23/MWh in 2021. Ratepayers will incur additional non-energy costs associated with offshore wind.

In the long-term, increasing amounts of offshore wind should drive down energy prices and increase grid reliability. While it is difficult to pin an exact monetary impact to these projects, more renewables and offshore wind will continue to shape the New York generation stack and could lead to more zero or negative price hours in energy spot markets.[66] Several of the projected online dates have been pushed back one to two years from their initial online dates, postponing the full impact these projects will have on ratepayers. Consumers won't likely begin to see an impact to their bills until 2024, when the first projects are expected to come online.

Offshore Wind Project Name	Contracted Capacity	Projected Online Date
South Fork Wind Farm	130 MW	late 2023
Empire Wind	816 MW	2026
Sunrise Wind	880 MW	2025
Empire Wind II	1,620 MW	TBD
Beacon Wind	1,230 MW	TBD
2022 Offshore Wind Solicitation	~2,000 MW	TBD

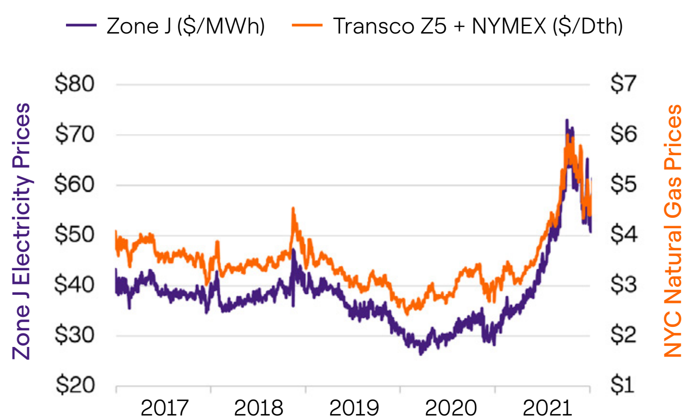
Source: NYSERDA

Spot Prices on the Rise, Renewables Could Alleviate Upward Pressure

Increasing renewable penetration in New York and stifled natural gas plant development will likely have a net-positive long term impact on ratepayers. With the full retirement of Indian Point Nuclear, the contribution of nuclear as a percent of NY's electricity mix dropped ten percentage points. At the same time, natural gas has surpassed hydro and now generates upwards of 25% of New York state's power (with another 22% coming from dual fuel plants).[67] As the marginal generating fuel, natural gas has helped set electricity prices in New York as shown in the graph to the right. The large run-up in gas prices in late 2021 has led to elevated spot prices for Zone J, which are on average double 2020 prices as shown below. The average day ahead spot price in February 2021 was 200% higher than February 2020, driven by expensive seasonal natural gas. While natural gas is likely here to stay in the near term, NYISO has recently signaled their commitment to halt the expansion of gas fired plants in the state.

NYISO recently denied two permits to expand existing infrastructure at natural gas fired plants in the state, signaling that it clashes with their state-mandated renewable goals of 70% zero-emission electricity by 2030. NYISO has a lot of work ahead of them—one projection pegs NYISO's 2040 grid mix as 33% offshore wind and 20% onshore wind. This is a far cry from the current <5% onshore wind and 0% offshore wind. The goal is ambitious but not impossible; it will require significant work to change NYISO's grid mix drastically over the span of twenty years. The impact of additional renewables on the grid will likely lead to lower and less volatile energy rates for consumers. There is also the added benefit of increased reliability, and much needed fuel diversity. It could result in higher non-energy costs for electricity end users.

Historical NYC Electricity and Natural Gas Prices



Historical prices trends show the relationship between Zone J electricity prices and Transco Z5 delivered natural gas pricing. Source: S&P

Average Monthly Day Ahead LMP – NYISO – Zone J

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Jan	$45.22	$81.20	$175.92	$57.34	$35.04	$40.64	$96.58	$49.20	$25.12	$36.35
Feb	$33.12	$90.67	$122.84	$112.33	$29.61	$30.55	$34.05	$33.07	$21.26	$64.78
Mar	$29.67	$48.82	$102.52	$51.26	$20.75	$36.04	$31.98	$35.00	$16.81	$29.40
Apr	$28.60	$43.94	$46.49	$27.53	$28.62	$32.27	$34.77	$28.82	$15.53	$24.55
May	$30.48	$45.25	$37.31	$30.35	$23.45	$31.61	$26.96	$23.39	$14.95	$26.11
Jun	$40.43	$43.65	$39.95	$24.95	$25.47	$30.17	$29.79	$23.41	$19.78	$34.84
Jul	$50.80	$60.14	$39.79	$30.01	$35.43	$33.57	$36.94	$31.23	$25.50	$42.00
Aug	$42.05	$40.12	$32.10	$31.10	$35.64	$28.66	$39.36	$26.59	$23.45	$46.90
Sep	$36.85	$39.89	$32.91	$32.45	$27.01	$26.26	$35.52	$21.49	$19.33	$48.41
Oct	$37.79	$37.55	$32.09	$27.68	$20.84	$27.88	$34.70	$19.86	$19.59	$54.47
Nov	$50.32	$40.82	$41.29	$23.34	$25.62	$29.97	$38.60	$26.55	$22.04	$57.10
Dec	$45.53	$61.14	$36.23	$20.24	$46.06	$49.54	$38.63	$28.53	$33.09	$47.29
AVG	$39.24	$52.77	$61.62	$39.05	$29.46	$33.10	$39.82	$28.93	$21.37	$42.26

Source: S&P

New England

Summary

Energy prices climbed in New England over the course of 2021.. Massachusetts Hub, for instance, saw its winter 2021/22 (Dec-Mar) contract rise as high as $164.76/MWh, the highest a winter contract has traded in more than twenty years. The reasons are familiar ones—global fuel supply constraints led oil and liquefied natural gas (LNG) prices to increase, while New England's pipeline capacity remains insufficient, with change unlikely in the years ahead. As a result, New England remains vulnerable to macro changes.

Key Takeaways

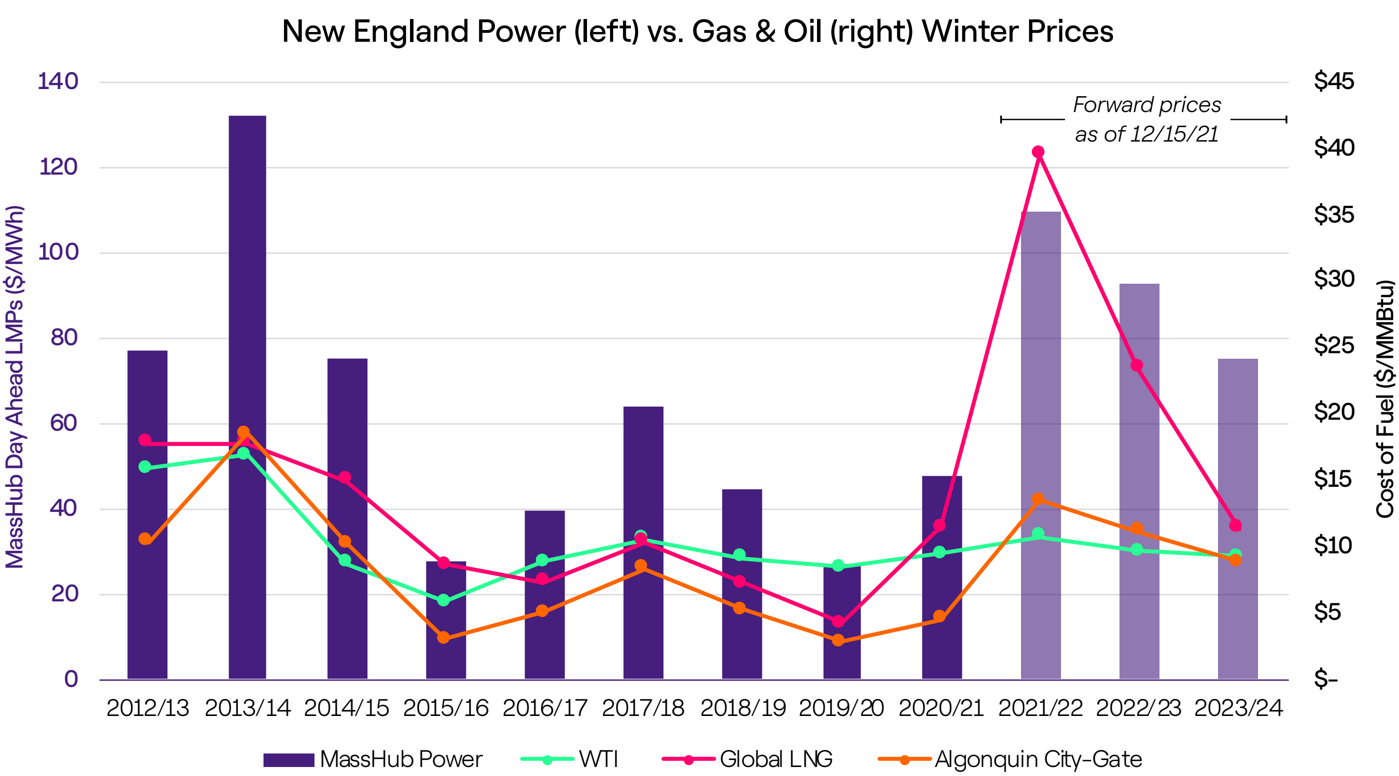
- New England states remain committed to a low carbon-emission future. In 2021, Massachusetts continued its efforts in renewable energy, with Governor Charlie Baker signing a new clean energy bill into law
- Commodity costs are high throughout New England, creating opportunity for organizations ready to revisit their go-to-market strategy

Exposed to Global Markets, ISO-NE Power Prices Reach Record Highs

Commodity prices climbed across North America in 2021, and New England energy prices witnessed the largest increase of the eight major deregulated grids. The increase was due to unique regional challenges, especially securing enough fuel during winter months to meet both heating and generation demand. Insufficient pipeline capacity into New England from neighboring gas rich states like Ohio and Pennsylvania means that dual fuel capable natural gas power plants must store and use substitute fuel such as residual oil and liquified natural gas (LNG) to produce electricity on cold winter days. New England's seasonal reliance on oil and LNG exposed the region to ongoing global supply chain shocks and associated price fluctuations, particularly as the world recovers from the pandemic.

The price of New England wholesale power to be delivered during calendar year 2022 more than doubled in the last nine months of 2021, as global fuel supply constraints emerged and oil and LNG prices increased by several multiples. The New England power benchmark, Massachusetts Hub, saw its winter 2021/22 (Dec-Mar) contract climb as high as $164.76/MWh in early October 2021—this figure is the highest a winter contract has traded in more than twenty years, exceeding even the average real-time spot pricing of ~$132/MWh during the 2013/14 polar vortex winter. For calendar year 2022, power prices rose from roughly $35/MWh at the start of 2021 to a high of $78.75/MWh by early October. By mid-December 2021, CY 2022 prices softened, but remained elevated, trading just below $70/MWh.

With New England states' sights on a low carbon-emission future, there is neither the political appetite nor private capital available to build new pipelines. Thus, with no significant additional pipeline capacity on the horizon, the region will continue to be reliant on domestic and global fuel supplies, and subsequently vulnerable to macro changes.



Sources: S&P Global; Platts; ICE; EIA; FRED

Massachusetts Commodity Costs to Eclipse 50% of Supply Costs in 2022

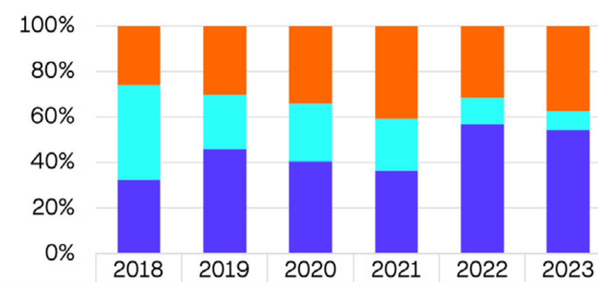
Following the meteoric rise in forward wholesale energy prices in the second half of 2021, commodity charges are anticipated to make up the majority of supply costs once again in Massachusetts starting in 2022, for the first time in five years. Based on forward prices as of late-December 2021, wholesale energy as a percentage of total supply costs in northeastern Massachusetts will rise above 55% in calendar year 2022 for many retail customers, compared to just 32% in 2018.

Capacity as a percentage of supply costs will shrink to just 12% in 2022 for an average large commercial end user in Massachusetts, down from an astounding 42% in 2018. The contraction aligns with what will be a five-consecutive year decline in capacity rates from 2017/18 to 2023/24, which is driven by the absence of any new large power plant retirements and substantial growth in demand response and behind-the-meter renewable generation.

While commodity prices will continue to fluctuate in the months ahead, we expect historically elevated energy prices to exceed the scheduled decline in capacity rates in 2022, with all-in rates for a sample large commercial customer in Massachusetts rising more than $0.01/kWh in 2022 compared to the year prior. It is important to note, however, that actual supply rates vary materially from organization to organization and depend on a variety of factors, including product structure, strategy, and each facility's unique load profile.

As the composition of supply rates change, so do the opportunities and levers to manage organizational costs. With commodity costs once again the largest component in a supply contract, on both an absolute and relative basis, customers may consider revisiting their go-to-market strategy. With electricity supply and delivery rates in New England among the top five highest in the country (often north of $0.165/kWh combined), and especially noteworthy rates in Massachusetts and Connecticut, this is a market that deserves attention.

Composition of Massachusetts Supply Costs



	2018	2019	2020	2021	2022	2023
Non-Energy (Volumetric)	$0.029	$0.031	$0.031	$0.035	$0.037	$0.037
Non-Energy (Demand)	$0.046	$0.025	$0.023	$0.019	$0.014	$0.008
Commodity	$0.036	$0.047	$0.036	$0.031	$0.066	$0.053

Source: Enel X Calculations

Massachusetts Passes Nation-Leading, Sector-Wide Energy Bill

Governor Baker signed SB9 into law, which creates the nation's first sector-wide clean energy bill, resulting in zero emissions by 2040. The bill promotes renewable energy targets, building electrification, zero emission car adoption and infrastructure building, internal combustion engine phase-out, and more.

Midwest

Summary

The Midwest region largely mirrored the Mid-Atlantic region—most states experienced no particular crises that affected price activity, but prices rose nonetheless in the wild 2021 market driven by factors outside MISO's borders. Even so, some states were affected by Winter Storm Uri. The power crisis raised concerns about grid reliability and led state regulators (particularly in North Dakota and Kansas) to conduct studies that could lead to new 2022 legislation.

Energy prices followed the natural gas trend and ended the year at the highest point in the past decade, but rising energy costs were partially offset by the drop in capacity pricing across the region. With the onset of a major energy transition, the Midwest has responded with revised zero carbon generation goals, sure to play a part in energy and ancillary pricing in 2022 and beyond.

Key Takeaways

- Natural gas concerns brought high prices for energy consumers in 2021, but expectations are for a lower 2022
- The 2022/2023 capacity auction produced a positive result for customers and illustrated sufficient generation capacity in the region
- Renewable study in MISO showed that states will need to drastically step-up efforts to reach necessary zero carbon goals; however, local opposition to new renewable development may slow the realization of those goals.

Midwest Power Pricing Saw Volatile End to 2021, but Hope in Store for 2022

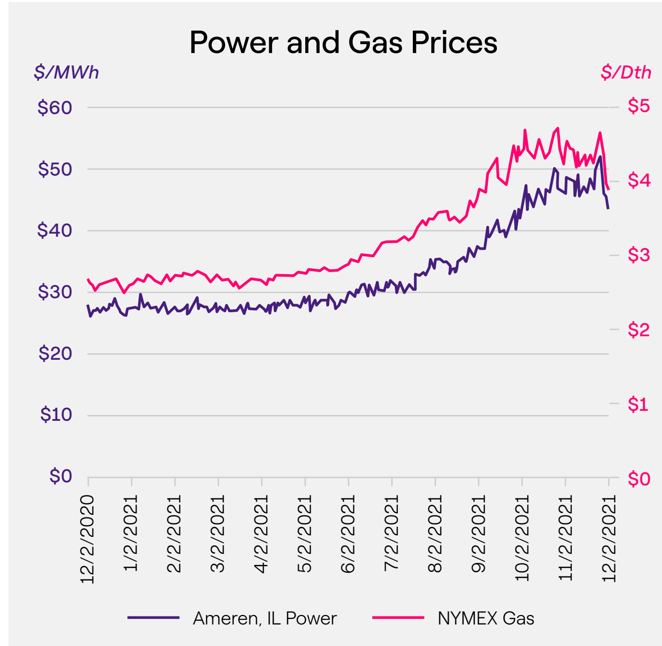
Following a sustained global trend, the US Midwest saw major upward swings in electricity pricing, closely tracking the natural gas price activity. Average hourly prices were double the marks set in the unusually low-priced 2020 calendar year. November and December of 2021 continued the wild ride and have provided some insight into the 2022 market environment. A very mild start to the 2022 winter suppressed the fear of an extremely cold winter, natural gas production and storage levels increased, and prices saw a significant decline late in the year.

Most of the Midwest region is still part of a regulated system, where competitive electricity choice is not yet available. This means that the impacts of the 2021 run-up in prices will be felt in a delayed fashion by utility customers whose rates adjust to market signals more slowly. End users can expect to see 2021 costs passed through in 2022 rate adjustments and utility fuel riders. Of particular note, several utilities plan to recoup hundreds of millions of dollars in cost increases from Winter Storm Uri over the next 2-5 years in a effort to make up for the extraordinary costs incurred due to the storm. Winter Storm Uri caused massive price increases to natural gas in KS & MO.

Deregulated market customers who may have seen electricity costs rise in the second half of 2021 will more than likely see the market cool off as 2022 goes forward. For customers with third party supply, it is increasingly important to keep an eye on wholesale markets and attempt to renew contracts in times of low volatility; mainly the spring and fall shoulder (lower usage) months.

Capacity Prices Fall to Historic Lows

A more positive note for Midwest customers is the result of the 2022/2023 capacity auction. The auction, held in the spring of 2021, saw major declines in cleared capacity



Source: S&P

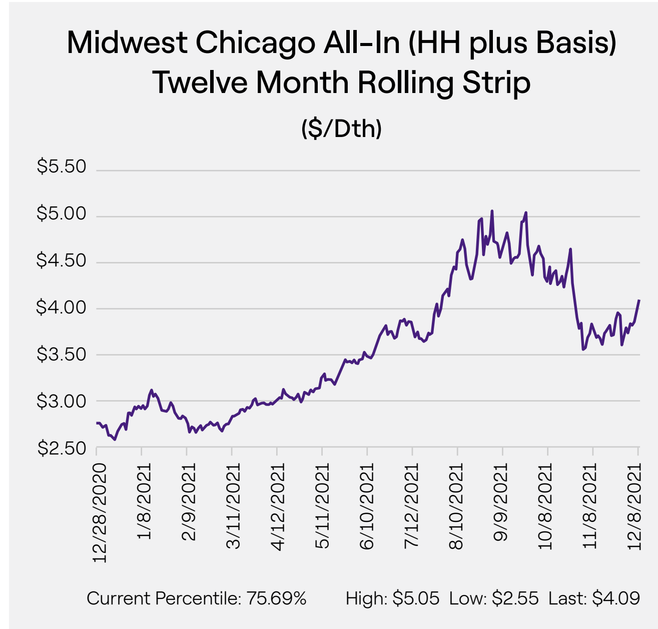
prices across the region. Most zones cleared at $.00021/KWh, similar to 2020. The Michigan zone (Zone 7) saw capacity prices drop off completely, from $.011/KWh to $.00021, a drop of over 95% from 21/22 levels. Customers on a capacity pass through contract, or still with the utility in Zone 7 will see these huge cost reductions to their capacity line item (given their capacity tag remains relatively unchanged). AR, LA, TX and MS all closed at $0.01/MW-day.

While these rock bottom prices may not last into succeeding auctions, the signals from these results show that the available Midwest capacity is expected to meet reliability requirements and should keep a lid on prices for the time being. The most recent survey from the Organization of MISO States is projecting that available capacity will exceed reserve margins in most zones, including the volatile zone 7. Given these capacity rates, it may seem advantageous to abandon programs designed to curtail usage during peak hours. Be advised that low rates may not last, and to drop a program only to reimplement it in a rising cost environment would be costly and time consuming. Those customers who are able would be advised to evaluate a fixed capacity contract to take advantage of low rates.

Natural Gas Prices Expected to Settle Down After a Wild 2021

Increasing natural gas supply coupled with mild temperatures to begin the year should keep downward pressure on average 2022 prices for the Midwest region. In Platt's North American Gas Regional Short-term Forecast, analysis shows steady production at 8.5 Bcf/day through March 2022, plus an additional 10.3 Bcf/day of inflows from the West, Northeast and Canada.[68] This is an increase of over 1 Bcf/day from December to March.

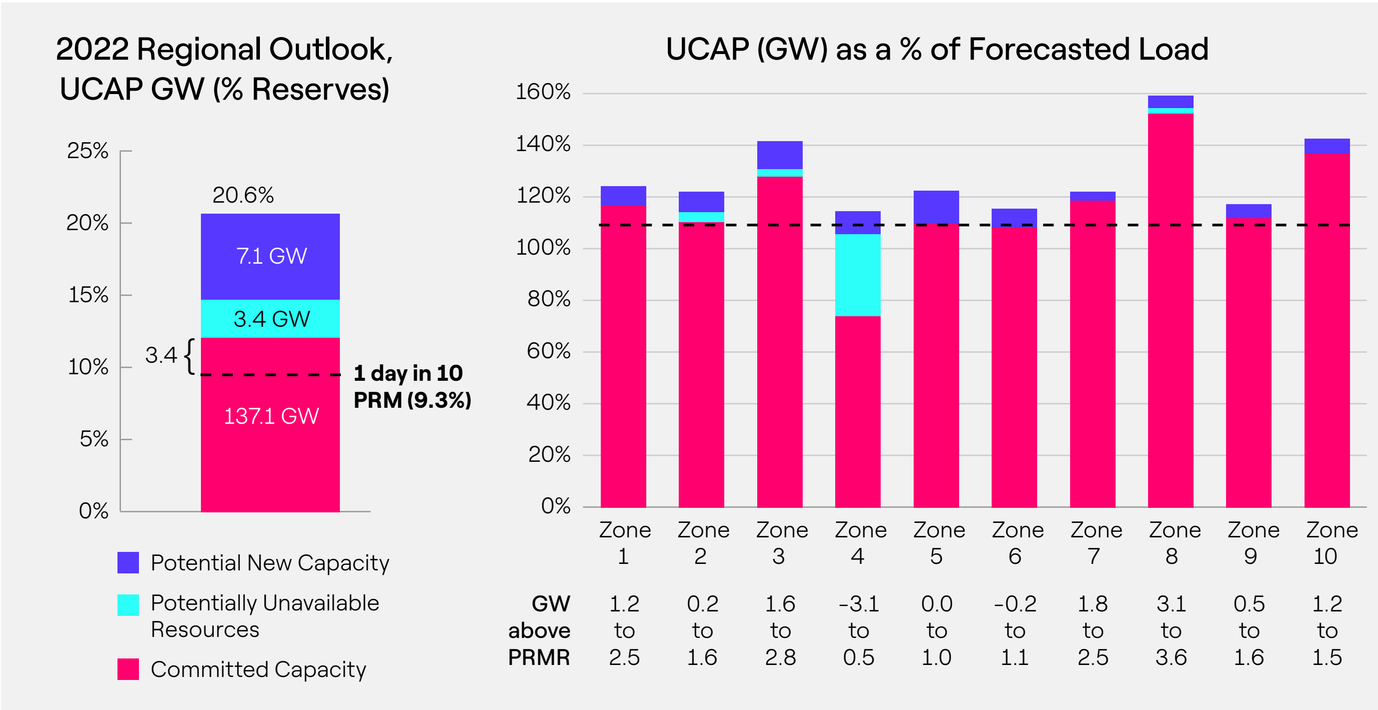
Spikes in the cash market are typical for winter with Chicago area prices spiking to a monthly average of $22 in February of 2021 during a cold snap. These types of spikes are certainly possible this winter, and customers should look to mitigate this winter risk with fixed price purchases to avoid these types of events. The 2021 market saw a rare volatile shoulder period in October and November due to a number of global factors, settling in a new "plateau." As the year ended natural gas supply concerns, storage deficits and weather factors started to subside, and prices in 2022 should follow suit.



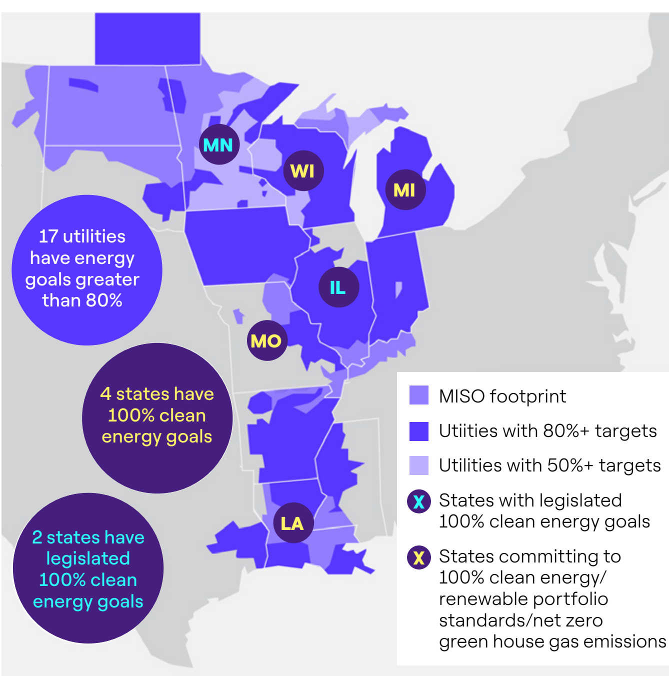
Source: S&P

The Future of Renewables in the Midwest

As the Midwest starts to look ahead from natural gas and other fossil fuels, states are ramping up their sustainability plans in preparation for the coming energy transition. MISO's Regional Resource Assessment (RRA) was released in December of 2021 and provides a comprehensive look at the region's generation resource plans and state renewable and carbon reduction goals.[69] A major point of emphasis is the 140 GW of new generation that will be required by 2040 and two-thirds of that new generation will need to be renewable or non-carbon-emitting. The magnitude of the 140 GW is noteworthy considering MISO's current installed capacity as of the end of 2021 is 199 GW total. Currently less than half of that renewable capacity is being planned, leaving a large outstanding balance needing to be filled.



Source: MISO



Source: MISO, "Regional Resource Assessment – Initial Version, November 2021"

Coincidently, the mandate for more renewables will require more natural gas fired generation capacity to maintain grid reliability. MISO expects that 20% more gas capacity will be needed, although overall gas generation will decrease 10%. In other words, the new gas generation will serve as stand-by for quick response to system needs in high usage situations. Note that these increased costs will be passed on to customers in the form of ancillary charges which fund grid reliability programs.

For 2022, we expect to see continued strong demand for renewable power purchase agreements (PPAs) from both vertically integrated utilities and corporate buyers. As can be seen in the accompanying map, state mandates are prevalent throughout the region and expected to be enhanced as the necessity of low-carbon generating sources is emphasized. However, this region is also seeing some strong local opposition to renewable energy development and rule changes that make it easier to block such construction.

Mid-Atlantic

Summary

The MOPR debate continued to drive the headlines in PJM for 2021 and undoubtedly will continue this year, with other regions closely following the outcome. As the result is settled, the PJM capacity auction prices will decide whether the transition to renewable energy will be fast paced or more drawn out, leaving a path for traditional brown power for the foreseeable future.

Nuclear power has long played a significant role in PJM. Though recent years signaled a possible fade from the market due to high generation price, in 2021 there was an indication that this may not be the case after all. States are increasingly recognizing the importance of nuclear power in a zero-carbon portfolio and intervening on behalf of nuclear generators. This could be a sign of hope for plants facing closure.

Key Takeaways

- Capacity market changes continue to drive the generation mix in PJM, with renewable and nuclear assets benefiting from the most recent reform.
- Nuclear plants see a glimpse of hope as state and potentially federal subsidies compensate them for their zero-carbon generation
- A strengthening of state renewable generation mandates supports the energy transition, however growing local opposition to siting renewable plants could cause headwinds to the implementation of state policy.

Capacity Market Reform and the Future of the Fixed Resource Requirement Decision In Virginia

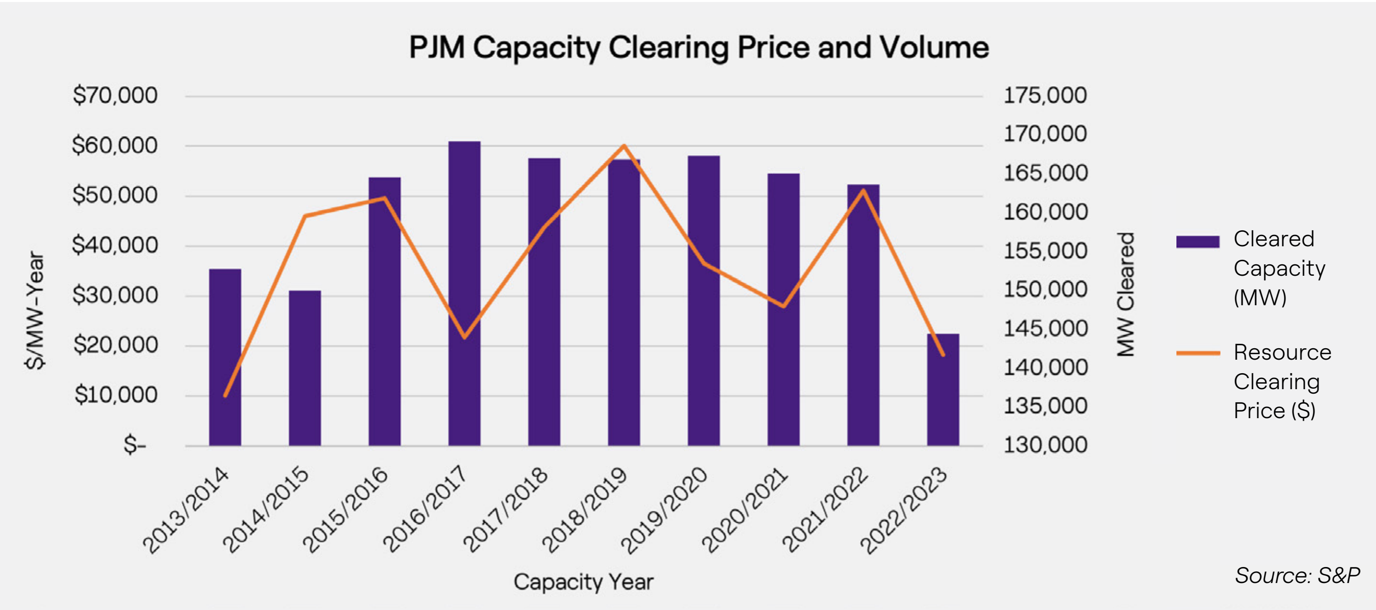
The enactment of the Minimum Offer Pricing Rule (MOPR) in December 2019 caused an immediate reaction from states and spurred calls for reform from both the public and private sector. FERC received significant backlash from states that have, to date, prioritized the transition to carbon-free generation through resource changes or policy tools. Likewise, companies with a stake in clean energy decried the negative effect that MOPR would have on their portfolio of assets.

The original 2019 MOPR ruling established strict guidelines around "out-of-market payments" and how they would be factored into a capacity auction. The result was that zero-emissions credit (ZEC) payments and renewable portfolio standards (RPS) would be newly included in that definition. These out-of-market payments were declared to be "unjust and unreasonable,"[70] meaning they were restricted from being considered in the calculation of a generator's capacity offer (cost to generate). This significantly affected renewables and, most importantly, nuclear assets, whose offers would be unable to clear the capacity market, denying them critical revenue and putting their continued operation at risk.

A revision was created and enacted in late September 2021 that redefines the MOPR application in the following ways:

- MOPR will only be applied to generators who are receiving Conditioned State Support, defined as payments made to a resource by state or federal government so that they may submit low bids on the condition that they clear the market. This might be utilized by states to lower energy prices.
- MOPR will NOT be applied to generators who are receiving Unconditioned State Support defined as legitimate exercise of state authority over the resource mix involved in power generation. At a high level, this re-focuses the MOPR rule and allows state subsidies to be considered in the calculation of capacity bids
- The order will be utilized to address Buyer Side Market Power (BSMP). The exercise of BSMP occurs when a generator that is also a load-serving entity submits artificially low capacity price offers. These generators have the goal of lowering the costs of capacity they pay for any of their load that they can't serve with their own generation. In the event this occurs, FERC will apply the MOPR to prevent this unfair practice.[71]

Despite the change in MOPR to accommodate state policy, there was a withdrawal by generators from the PJM capacity program as a result of the detrimental effect to zero carbon goals. Dominion Energy elected to pull its generating assets out of the Reliability Pricing Model (RPM) and to utilize the Fixed Resource Requirement (FRR) instead.[72] A PJM requirement is that a utility opting for FRR must elect to stick with the program for at least five years so we have yet to see what this decision will mean for Dominion customers' capacity cost.



Seen in the chart, the market developments from the MOPR ruling in 2019 resulted in a significant dip in the capacity clearing price and the number of megawatts (MWs) that cleared the 2022/23 Base Residual Auction (BRA). The impact of the Dominion withdrawal from the BRA is estimated to have caused about half of the drop from 21/22 prices. From a volume (MW) perspective, this is explained by the fact that some generators will have been forced to bid much higher, thus not achieving the clearing price of $50 for the 22/23 planning year. With the passing of MOPR reform, changing the rules around the minimum offer price while receiving subsidies, the volume clearing the market will remain below previous levels but capacity pricing is expected to remain low as states continue to support renewables with tax credits and subsidies.

It is important to remember that utility rates for capacity can vary based on the need for generation in a particular area. While the PJM region clearing price was $18,250/MW-Year for 2022/23 (amount paid by a customer with a 1 MW capacity PLC tag), other regions can clear higher or lower depending on generation needs. For example, BGE which has generation constraints, cleared much higher for 22/23 at about $47,500/MW-Y when applying applicable zonal scaling factors. This rate is down around $23,000/MW-Y from the 21/22 rate, a 32% reduction.

As capacity auctions are carried out, the effects of MOPR will become clearer. Below is a schedule of when the auctions are held and when public auction results will be published for each delivery year.

Auction Delivery Year	Opening Date	Results Posted
2022/2023 Base Residual Auction	5/19/2021	6/2/2021
2022/2023 3rd Incremental Auction	2/28/2022	3/11/2022
2023/2024 Base Residual Auction	1/25/2022	2/7/2022
2024/2025 Base Residual Auction	6/15/2022	6/28/2022
2025/2026 Base Residual Auction	1/4/2023	1/17/2023
2026/2027 Base Residual Auction	7/5/2023	7/18/2023

Source: S&P

A Nuclear Rescue Package

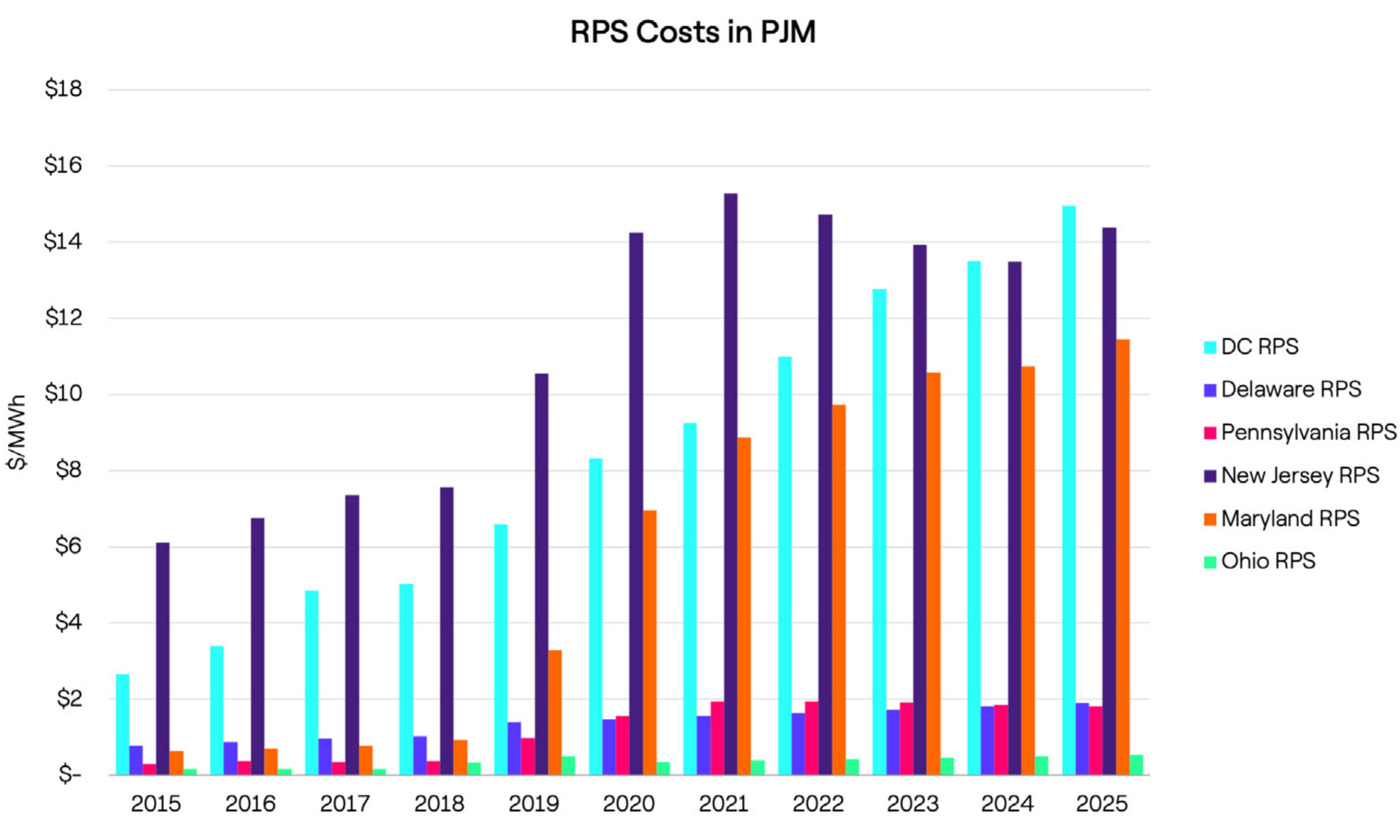
Another longstanding issue has been the importance of nuclear generation plants to both grid reliability and as a source of carbon-free energy production. The value of nuclear in these two respects cannot be understated; the real debate, however, is how we reconcile these benefits financially. Nuclear is substantially more expensive to operate than natural gas or renewables, with high fuel costs, employee payroll and huge initial investments. In the recent environment of slowly declining power prices due to natural gas (2021 notwithstanding), nuclear assets risk not clearing the capacity market, meaning no capacity revenue, which can devastate a nuclear generator. Several states have recognized the benefits and chosen to provide support with state funds, allowing otherwise uneconomic nuclear plants to continue operations.[73] Important to note that this state support was directly defined in the MOPR ruling, but, as explained above, has been largely revised so that nuclear can still offer competitive prices.

This action has already been taken in PJM, with New Jersey and Ohio (albeit with a major scandal related to the legislation), NYISO (New York) and it is being considered in Pennsylvania. Illinois, the state with the most nuclear capacity, has recently passed a bill to provide state support for its nuclear fleet, which fall in the PJM portfolio. The rescue of these generators will play a role in keeping consumer capacity costs low, directly benefitting the everyday customer, but is also a force to drive down capacity prices for other resource types in the region. The coal fleet in Illinois will be operational until 2030, when these resources will be expected to close.

Renewable Portfolio Standards: A Growing Focus

State renewable portfolio standards (RPS) are a continually evolving entity, and one that will have significant impacts to the generation mix as well as end-user energy supply costs. PJM states have continued to revisit previously set mandates which required a certain percent of renewable energy, and additionally, the types of generating assets that qualify for the program. Maryland is the most recent state to rearrange their standard, lowering the state-required amount of solar, which opens opportunities for other renewable sources to reach their goal. Pennsylvania has an outstanding bill that would significantly increase both the total tier 1 renewable requirement percentage from 8% to 18% and require that a minimum of 5.5% of that 18% come from solar sources.[74] Below is a trajectory of RPS rates by state through 2025.

For customers, this means a higher proportion of the supply costs are coming from state RPS. Particularly aggressive goals set by Washington DC and Maryland will cause significant increases to RPS costs based on current projected Renewable Energy Credit costs and state RPS percentages. It is important to note that a change in law or major REC price fluctuations could significantly impact projected costs and can be passed through to customers, even those on fixed price contracts.



Sources: S&P and internal Enel X calculations

Canada

Summary

Energy prices are on the rise in Ontario and Alberta, especially when compared to the low prices seen in 2020. In Ontario, rising energy prices are met with lower global adjustments (GA) costs—bringing down the all-in rate for the average consumer. Natural gas remains the key driver for the summer price volatility seen in 2021, despite making up 1% to 10% of generating capacity on the Ontario grid depending on the month. Given the low likelihood of seeing natural gas generation phased out over the next ten years, consumers can potentially look to third-party supply to mitigate the risk associated with seasonal volatility. Alberta, where gas makes up a much larger portion of the generating fleet, has also seen increasing prices in 2021. If passed, a new law would allow consumers to self-supply electricity and take advantage of battery storage incentives to help reduce their grid purchased electricity.

Key Takeaways

> Ontario energy prices are up significantly year-over-year. Overall electricity costs are lower than 2020 driven by lower global adjustment rates.

> High summer electricity demand in Ontario led to more natural gas online in summer 2021 and higher summer prices. We likely will not see the phaseout of gas generation over the next ten years, which could lead to increasing price volatility associated with elevated gas costs.

> Alberta prices are higher year-over-year as legislation is considered to modernize the grid

Ontario: Rising Energy Prices Meet Falling Global Adjustment Rates

Canadian power markets have witnessed a significant uptrend since the lows seen in 2020 driven by rising natural gas prices. During the first three quarters of 2021, hourly Ontario energy prices (HOEPs) averaged 92% higher than the same period in 2020.

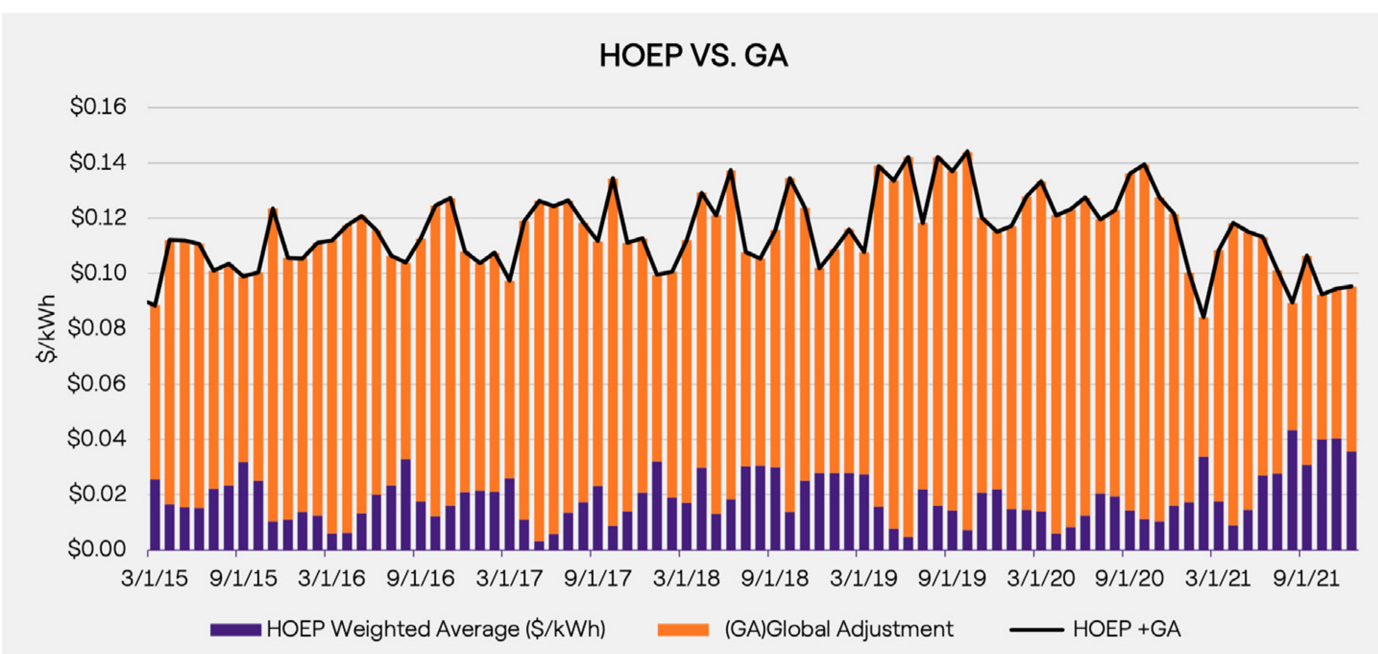
We can also expect these elevated prices going forward into 2022/23—the Ontario Energy Board (OEB) is forecasting HOEPs for 2022 to be well above historical averages. Based on a study published in late 2021, the OEB forecasts the HOEP to average $32.88 in 2022 and early 2023. This represents a significant increase from historical averages.[75] The more immediate Feb 2022 – April 22 time period is forecasted to be closer to $37.13/MWh, which would be a 84% increase year-over-year and a 220% increase from the same period in 2020.

Alongside HOEPs, the other major cost component for Ontario ratepayers is the global adjustment (GA) charge. Typically, the GA is inversely proportional to HOEPs, which means we have seen an overall downtrend in GA rates during 2021. Additionally, in November 2020 the provincial budget included a proposal to reduce GA costs by shifting non-hydro renewable energy generators' cost from the rate base to be recouped by taxes. This has reduced the number of programs that are recovering costs through the GA charge and subsequently has led to lower rates year-over-year. Despite rising HOEP costs, all-in electricity costs (HOEP + GA) for January through October 2021 were ~$0.025/kWh lower than the same period in 2020. For a 5 million kWh per year customer, this translates to $125,000 in avoided costs when projected out for a full year.

HOEP Settlement Prices and OEB Forecasted Prices ($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2020	14.80	14.50	13.90	6.10	8.30	12.50	20.50	19.40	14.40	11.30	10.50	16.00
2021	17.40	33.80	17.60	8.90	14.60	26.90	27.60	43.40	30.70	40.00	*40.40*	*33.61*
2022	*33.61*	*37.13*	*37.13*	*37.13*	*25.39*	*25.39*	*25.39*	*28.51*	*28.51*	*28.51*	*35.81*	*35.81*

Source: IESO.ca



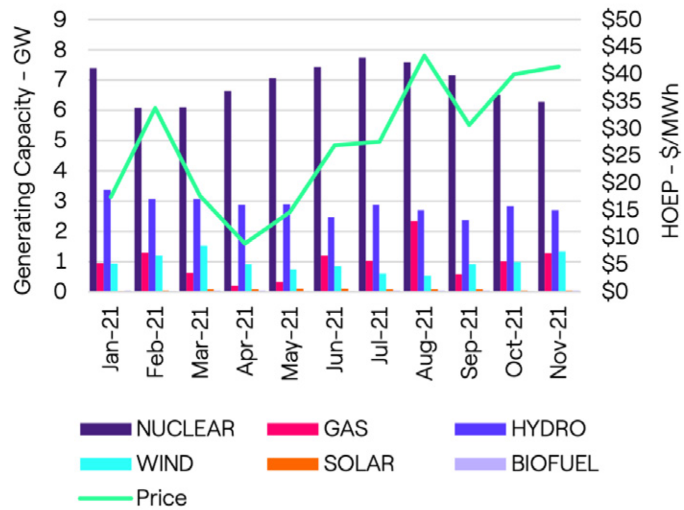
Combined HOEP and GA costs. HOEP prices have been on the rise in 2021 which has been balanced out by falling GA rates. Ratepayers are paying on average lower prices compared to 2020. Source: IESO.ca

Natural Gas Heats Up the Grid Mix and Prices

Ontario's seasonal grid mix remains a key driver for HOEPs. Depending on the month, nuclear and hydro facilities generate between 75%-90% of Ontario's power. In high-demand months natural gas picks up the slack—providing up to 10% of Ontario's power in August 2021, as shown in the chart on the right. The extra gas generation needed to meet demand during the summer heatwave brought HOEPs to $43/MWh in August 2021, a significant increase from April 2021 HOEP of $9/MWh when gas only accounted for 1% of the grid mix.

Futures markets are not necessarily signaling concern around the grid mix going forward. The August 2022 forward price is trading at a $3/MWh premium as compared to April 2022 contracts. Prices could come in higher or lower than where futures are trading depending on the grid's demand, resource mix and the price of gas. As HOEP prices are on the rise, third party supply contracts become more competitive. Historically, third party supply contracts in Ontario have not been economically feasible. However, if the uptrend in energy prices continues, switching to third party supply to minimize market exposure during volatile months could be cheaper than remaining on HOEP.

IESO Generation Type by Month + HOEP Price



Ontario hourly energy prices (HOEP) alongside the grid mix for respective months.

Natural Gas Is Here to Stay, for Now

We could see a continuation of the recent energy price volatility as gas futures remain elevated. Despite this volatility and mounting pressure from local governments for action, natural gas generation is likely here to stay in Ontario.

Citing environmental concerns, thirty municipal councils in Ontario have called for the complete phaseout of gas-fired generation by 2030. In response to this, a 2021 study published by the Ontario grid operators (IESO) shows completely phasing out natural gas generation by 2030 could result in rolling blackouts and unnecessarily high costs for consumers, at the cost of a relatively small emissions reduction.[76] IESO cited that the 11,000 MW of gas generation would need to be replaced by 17,000 MW of renewable capacity and about 1,600 MW of energy efficiency/conservation projects to meet the grid's future demand. This would incur an estimated $27B in costs for the new supply and transmission infrastructure according to IESO's report.

IESO has not completely ruled out getting rid of gas, stating that the phase out of natural gas over a 10+ year timeframe would be feasible, similar to how Ontario's coal-fired generation was phased out over a twelve-year period. But for now, the seasonal volatility around energy prices linked with natural gas is likely here to stay. Third-party supply contracts could be a way to hedge against future seasonal volatility if HOEPs continue their uptrend. A large consumer could also look to reducing their grid electricity purchases through onsite renewables or hedging against grid purchases through a renewable Power Purchase Agreement.

Alberta: Rising Price and Proposed Modernization Legislation

Similar to Ontario, energy prices in Alberta were on the rise in 2021 due to increasing natural gas prices year-over-year. Natural gas or combined cycle generation accounts for 30-40% of Alberta's electricity generation and plays a significant role in setting electricity prices. The average 2021 Alberta spot pricing was over double 2020 prices, with February and June 2021 averaging at a 300% increase from their respective months in 2020. Prices in 2020 were driven to decade-plus lows by weakening demand and suppressed natural gas prices. Given the run-up in gas prices observed in 2021, the increase in electricity spot pricing seems expected.

One method to combat rising energy prices is by allowing for fuel diversification, incentivizing the build-out of battery storage technology and supporting energy independent businesses. Bill 86, the Electricity Statues Amendment Act (ESAA), seeks to do all of these in under the scope of "modernizing Alberta's electricity grid." The ESAA aims to create a regulatory framework to support new battery storage technology on the Alberta grid. Namely, it will allow distribution and transmission owners to recoup the costs of battery ownership in their rates. At this point in time, the ESAA does not give details on how these costs would be recouped. The legislation proposes unlimited self-supply with no cap on grid exports. Under current regulations, only a specific subset of end-users are allowed to export power to the grid. The ESAA states that self-supplying market participants could pay a tariff based on their gross electricity consumption, as opposed to only their grid purchases.

While this could impose additional costs for businesses that are able to self-supply electricity through renewables or a cogeneration system, it is too early in the legislative process to put a value on the magnitude of the potential impact. This is important to keep in mind if you are planning on building a large behind-the-meter solar or wind system at your facility.

The programs highlighted under the ESAA will ultimately benefit the Alberta grid. Savvy businesses and municipalities will be able to take advantage of the battery storage incentives and self-supply allowance to reduce costs while aiding in the grid's modernization.

Average Monthly Pool Price

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
2014	$45	$96	$44	$31	$54	$42	$123	$45	$24	$27	$38	$27	$50
2015	$34	$33	$21	$21	$54	$97	$23	$34	$21	$21	$21	$21	$33
2016	$22	$17	$15	$14	$16	$15	$18	$18	$18	$25	$16	$24	$18
2017	$24	$22	$21	$19	$22	$17	$27	$25	$22	$20	$25	$22	$22
2018	$41	$31	$32	$41	$64	$63	$58	$69	$36	$63	$59	$44	$50
2019	$38	$109	$65	$41	$75	$54	$41	$45	$54	$42	$56	$43	$55
2020	$121	$36	$42	$29	$26	$35	$54	$41	$36	$61	$38	$38	$47
2021	$73	$152	$67	$88	$85	$141	$124	$82	$94	$96	$99	$124	$102

Source: ets.aeso.ca

Mexico

Summary

Energy prices in Mexico increased over 2020 levels, but did not approach levels seen in 2019. The political situation in Mexico continues to have a major impact on the future of Mexican energy, with many consequential rulings on energy expected in 2022. It will be important for businesses to closely monitor these decisions, as they could have a significant effect on energy prices.

Key Takeaways

> Like elsewhere in North America, regional electricity prices have been sensitive to natural gas prices and fluctuations in temperatures.

> Renewable production increased year-over-year in 2021.

The Importance of Politics in the Mexican Energy Industry

Politics plays an important role in the future of the Mexican electrical market. The current government has proposed reforms that gives more power to the CFE, the governmental electric generation enterprise and, with these, an increase in tariffs would be expected, due to the higher prices of CFE compared with private generators and the use of emissions-heavy technologies. Nevertheless, internally the congress is divided, and high pressure from private companies and the US government could impact the coming decision on the approval of the reform. A congress decision is expected by the first quarter of 2022.

Developments in the Electricity Industry Law

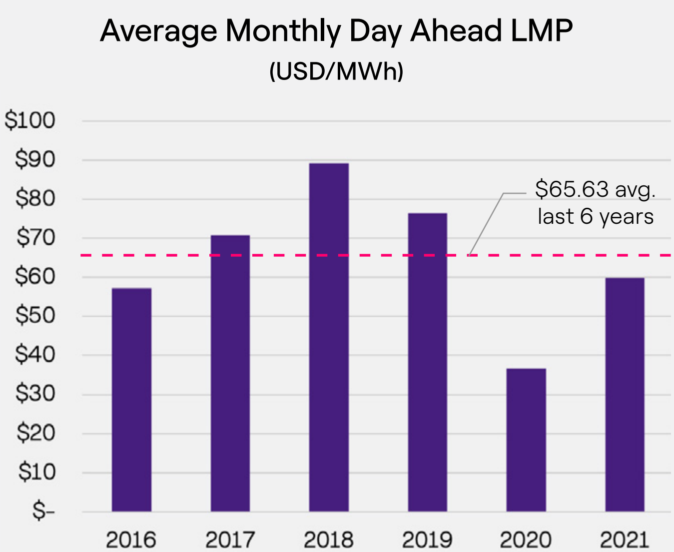
In 2021, consumer protection was granted against the Electricity Industry Law. This approval supports the idea that the changes suggested by the president of Mexico go against principles of economic competition and sustainability in the country. For end users, this is a good omen and allows the suppliers for whom the protections were approved to continue operating in the market in a normal way under the rules initially established. End users are also granted choice of supplier, and also get the benefits of migrating to an open market that translates into savings ranging from ~6% to ~35%, depending on the supplier of choice.

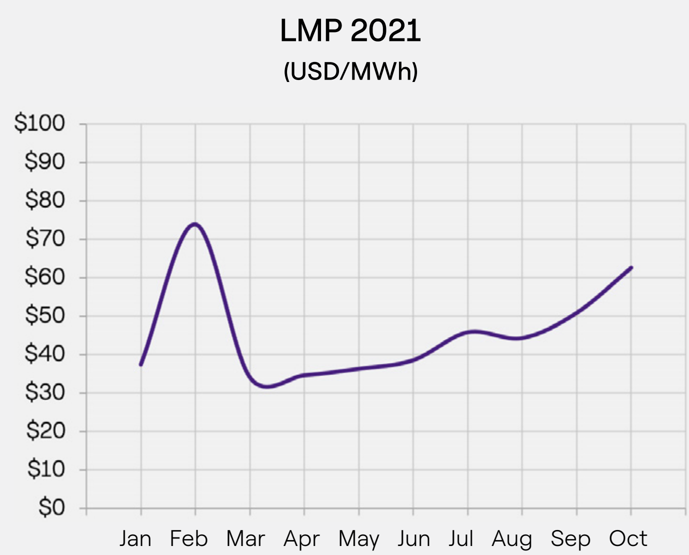
Government Sets Maximum Price for LPG

By establishing a maximum price for LPG in 2021, end consumers will be protected from abuses by suppliers where the price was not controlled. In turn they can opt for new alternatives such as virtual gas pipelines, which can generate savings of up to ~ 20% or more. This will help the sustainability policies of the clients, as reflected in reduction of CO_2 emissions. In addition, the fuel change can be done in months, with little or no investment.

Wholesale Markets

Day Ahead LMPs for 2021 (through October 2021) averaged \$59.83/MWh, up 64% compared with the 2020 and 22% lower compared with 2019. Electricity in Mexico is strongly correlated with the natural gas prices, since almost two-thirds of the country's generation is from natural gas. The highest price in 2021 was in February, in the wake of the Texas winter storm and the important rise in natural gas prices, though in late 2021 an increase in the Day Ahead LPMs occurred, following the increase of natural gas prices.

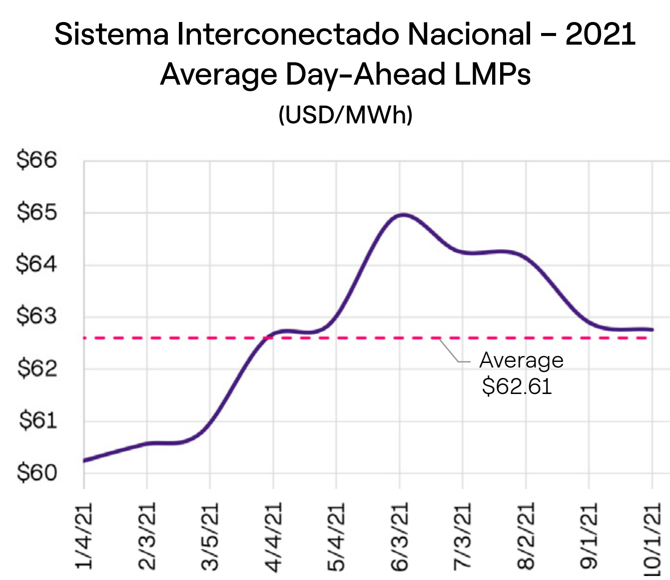




Source for both charts: CENACE data accessed via cenace.gob.mx

Retail Price Trends

Through October 2021 the average price of the CFE was 62.62 USD/MWh; during the same period in 2020 the CFE price averaged 62.95 USD/MWh. The first 5 months of 2021 have higher prices than the same period in 2020, and for the rest of the year, the tariff is ~.5% above 2020.

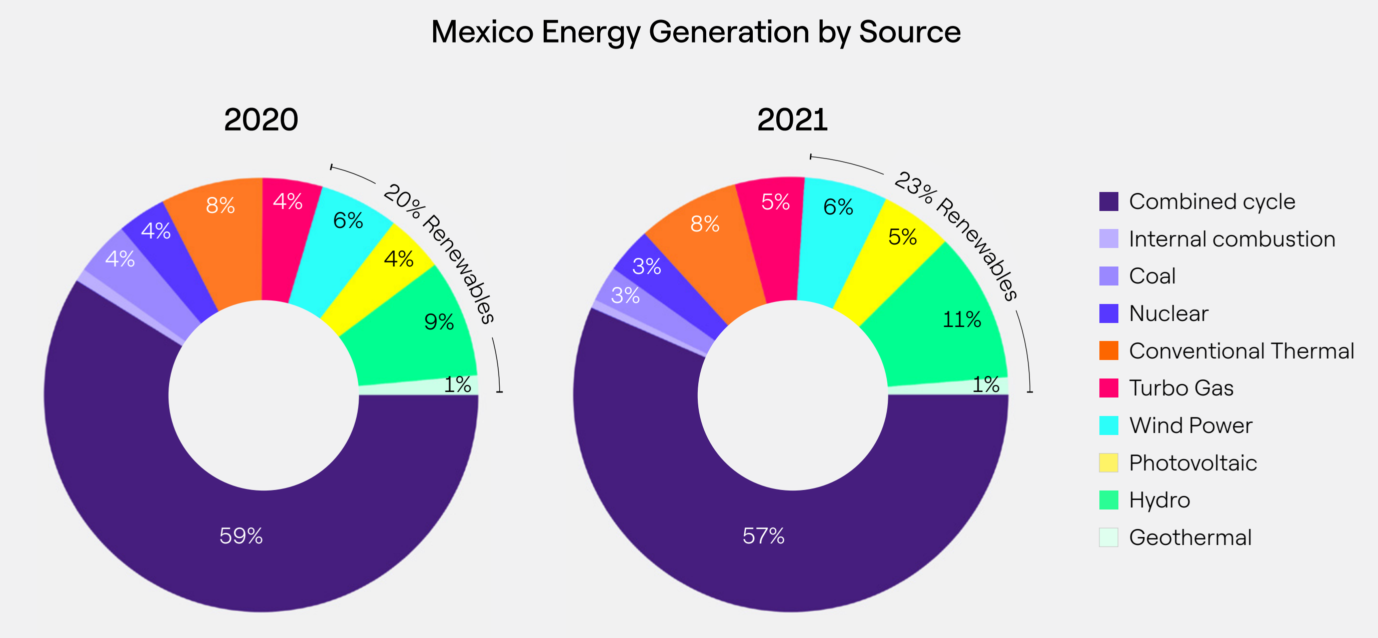


Source: CENACE data accessed via cenace.gob.mx

Renewables

Renewable energy as a share of total generation grew in 2021. Through October 2021, total generation in Mexico was 274,176 GWh (excluding the Baja California Peninsula). Of this, renewables account for approximately 23% (composed of hydro, solar PV, wind power, and geothermal).

In the same period of 2020, there was 263,841 GWh generated (excluding the Baja California Peninsula), with renewable energy constituting only 20% of the energy produced.



Source: CENACE data accessed via cenace.gob.mx

Chicoasen Hydroelectric Dam

What Does This Mean for You?

The energy world saw a great deal of change and volatility last year, and many of the drivers of that volatility—supply chain disruption, inflation, climate change, and the pandemic—remain. Organizations looking to adapt to these challenges in the near-term and plan for the long-term have to be sure their energy strategies balance these factors with their business goals.

Enel X can help plan an effective energy strategy for the future. Enel X's team of energy advisors can help businesses minimize their energy costs, lower their risk, and achieve their sustainability targets. We work with you to understand your business goals and energy needs, and then take steps to optimize your energy decisions.

Contact Enel X

To learn more, please visit enelx.com/northamerica.

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