S&P Global
Ratings

Industry Top Trends 2022

North America Merchant Power

Focus Turns To Power Resiliency

This report does not constitute a ratings action

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What's changed?

Focus on firm power. The market now expects renewables to deliver more than interruptible power, focusing not just on clean, cheap power but power that is also firm and scalable.

Appetite for nuclear is now increasingly supported through state mandates. There is a broader recognition that net-zero targets require nuclear in the resource mix.

The IPP model. We see independent power producers (IPPs) shifting away from merchant fossil generation through a combination of vertical integration and coal retirements/divestments.

What are the key assumptions for 2022?

Accelerated de-carbonization along with policy support is a major tailwind to sector growth. A tax credit approval for nuclear, stand-alone batteries, and hydrogen facilities would stimulate the clean power segment. While still likely, we have not assumed an approval.

Backwardation in power curves lifting. COVID-19 has taken out a couple of years of growth, and the declining cost curve of renewables continues to influence power curves. However, the inability of renewables to deliver firm power is resulting in higher energy prices.

What are the key risks around the baseline?

Capacity markets. Pricing could be lower than last year in the New England and PJM Interconnection auctions, while the New York auction could see another low year.

Investments in renewables to slow. Renewables deployment will slow in 2022 owing to supply chain issues. This poses both a risk and an opportunity based on the resource mix and nimbleness of a generator's assets.

Battery and hydrogen scaling. Battery and hydrogen subsidies could lead to a meaningful scaling in California, New York, and New England, and dampen expectations for scarcity prices.

Ratings trends and outlook

North America Merchant Power

Chart 1

Ratings distribution

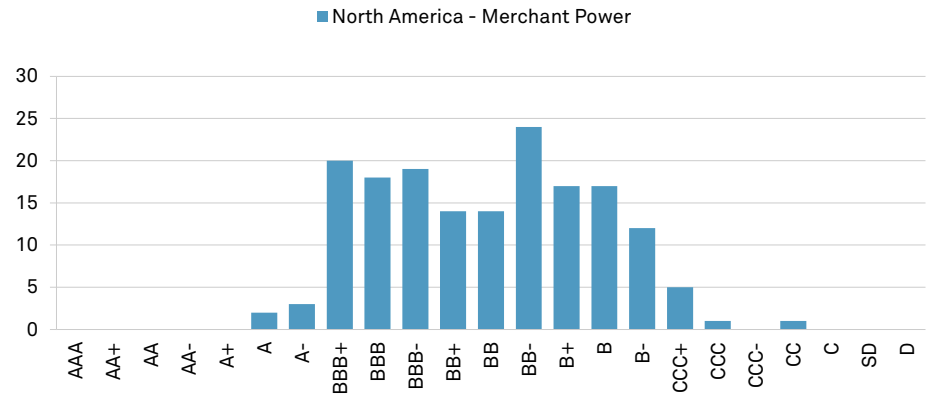


Chart 2

Ratings outlooks

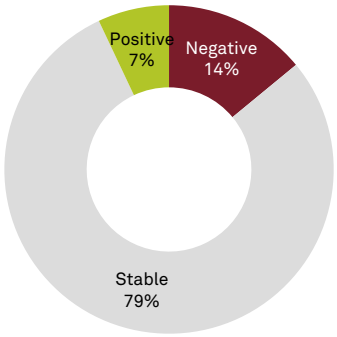
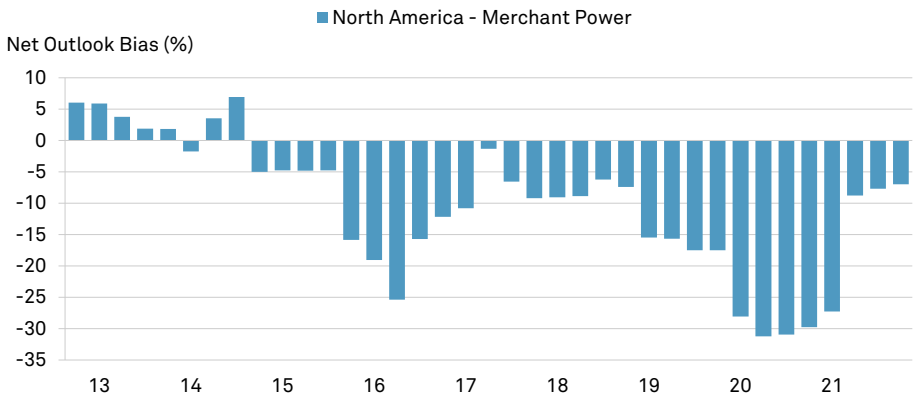


Chart 3

Ratings outlook net bias



Source: S&P Global Ratings. Ratings data measured at quarter end.

Compared to 2020, our rating distribution in the merchant power sector has strengthened in the 'BB' category, where it has moved into (the average ratings were 'B+' in 2018). Partly contributing to the move is the stable ratings of renewable portfolios and consolidation in the industry. Investment-grade credit quality has also strengthened, following three years of deterioration. Negative outlooks have declined to 15% as of Dec. 2021 compared with 24% in Dec. 2020.

Industry credit metrics

North America Merchant Power

Chart 4

Debt / EBITDA (median, adjusted)

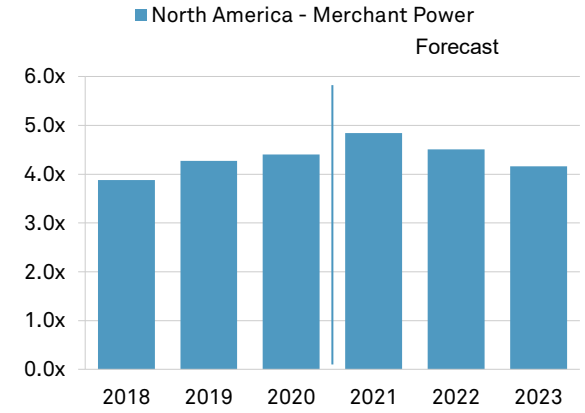


Chart 5

FFO / Debt (median, adjusted)

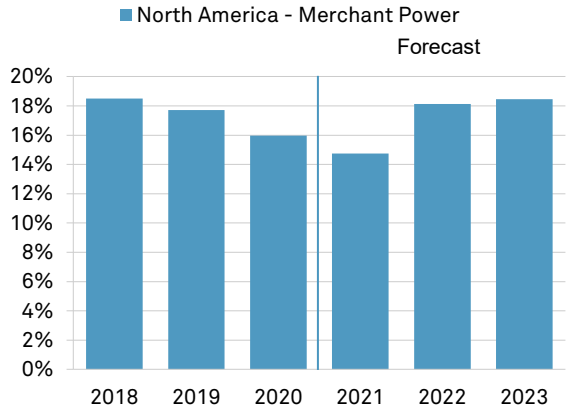


Chart 6

Cash flow and primary uses

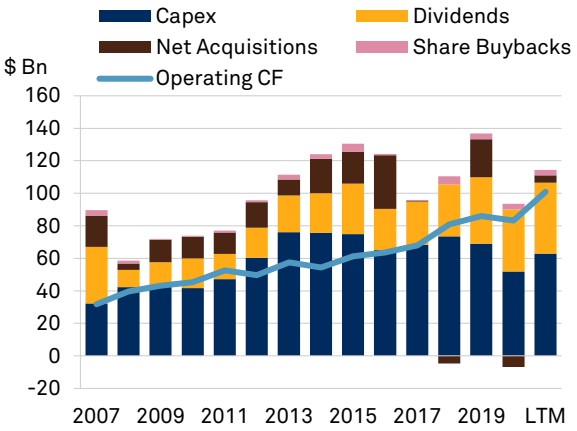
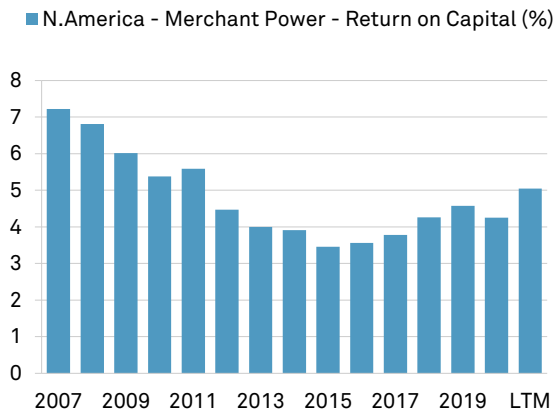


Chart 7

Return on capital employed



Source: S&P Global Ratings, S&P Global Market Intelligence. Most recent (2021) cash flow and ROCE figures are using last twelve months (LTM) data. All non-forecast figures are converted into U.S. Dollars using historic exchange rates. Forecasts are converted at the last financial year-end spot rate. FFO—Funds from operations.

We expect ratios to marginally deteriorate even as companies are shedding debt concomitant with expected declines in future cash flows. Partly contributing to this is the impact of winter events that slowed deleveraging efforts of major IPPs. We note that debt reduction remains the stated objective for a number of IPPs. Two years ago, expectations for aggregate debt/EBITDA and funds from operations (FFO) to debt were above 4.0x and 15%. Fully or largely contracted companies, such as Yieldco's target 5.0x debt/EBITDA, distort the overall averages. Most IPPs have targets of adjusted det to EBITDA in the 2.5x-3.0x range and adjusted FFO to debt above 25%, on a sustained basis. However, the timeline to get to these levels is delayed to the end of 2023 as some companies have also prioritized share repurchases to keep equity markets interested.

Industry outlook

Ratings trends and outlook

About 78% of our IPP or merchant generators have stable outlooks. This compares with just 70% last year and 85% two years ago. While larger IPPs have shown greater stability, the smaller ones with no retail operations are the ones that have negative credit trends. The business outlook still reflects a secular declining trend in demand because of energy efficiency, behind-the-meter solar, and distributed generation.

Main assumptions about 2022 and beyond

1. Inflation, rising interest rates, and supply chain disruption could be challenging

Many companies kept operating and maintenance (O&M) costs flat or managed to lower them in recent years, with labor attrition and technology advances offsetting inflation. However, as materials costs increase, those pressures could start to influence margins in 2022.

2. Secular demand assumed to increase by 1%

S&P Global's U.S. economic outlook is for GDP to grow by 3.9% in 2022 and by 2.7% in 2023. Additionally, we assess the recession risk at just 10%-15%. In 2021, electric demand was up 2.8%, following a 2.9% decline in 2020. We are projecting loads to grow 1% year-over-year in 2022; some regions could experience flat growth.

3. Global gas prices will influence energy markets through 2022, if not longer

Natural gas markets have increasingly globalized with seaborne liquid natural gas (LNG). In 2021, higher gas prices in Europe and Asia pushed up U.S. gas prices due to combination of LNG export dynamics, lower gas-to-coal switching, and an increasing number of coal plant retirements.

4. Path of renewable proliferation dominates power market forwards

Renewable proliferation has three drivers: a) The need for energy to replace uneconomic fossil plants retiring; b) increasingly competitive levelized cost of energy as the cost curve declines (with full subsidy wind and solar approaching the low- and mid-$20/MWh area, respectively); and c) meaningful commercial and industrial (C&I) demand, particularly with corporate procurements driven by sustainability goals.

We expect weak capacity market auction results in 2022. In New York, the market outlook has been dampened by lower preliminary values for the 2022 peak load forecast, which are lower by 3% compared to expectations in 2021. This has the potential to significantly pare down expectations for capacity prices recovering in New York City (Zone J) after the dramatic fall last summer. We now expect summer 2022 to clear at similar levels as summer 2021 of about $5.0-$5.5/KW-month.

Similarly, the decline in installed capacity requirement in New England's forward capacity auction (FCA16) is not only driven by lower load forecast compared to FCA15, but also because of New England's passive demand resource (PDR) reconstitution methodology. We do not expect the load forecast to recover to the FCA15 levels due to PDR reconstitution for several years, resulting in our expectation that the auction price will be between $2.25-$2.75/KW-month for the next three or four auctions.

The PJM too released its annual load forecast report in December 2021, reflecting the outlook for 2022-2032. While lower demand revisions have become an annual tradition, the latest update comes despite the addition from higher electric vehicle (EV) load in later years. We now forecast EVs to represent 1GW summer peak capacity by 2027. With reduced demand parameters, we expect similar low auction prints following last year's $50/MW-day regional transmission organization (RTO) price. We not only expect a dramatic pullback to RTO pricing levels in the ComEd zone but also lower auction outcomes in all regions--with the Mid-Atlantic Area Council (MAAC) around $80/MW-day and Eastern MAAC (EMAAC) around $100-$105/MW-day.

We expect energy prices to provide some mitigating offset. In 2021, we saw the resurgence of elevated global gas prices due to:

- Post-COVID pent-up demand out of Asia
- Low European storage inventories, and
- Limited gas-to-coal switching as coal plants retired.

Natural gas markets have increasingly globalized with seaborne LNG. In 2021, higher gas prices in Europe and Asia pushed up U.S. gas prices due to combination of LNG export dynamics (U.S/Europe and U.S Asia arbitrage), lower gas-to-coal switching due to coal supply chain disruptions (e.g. railcar challenges), and an increasing number of coal plant retirements. In the past, high availability of coal mitigated volatility in power markets because of gas-to-coal switching when natural gas prices rose. Now, power prices across the U.S. have rallied given the upward gas price pressures. Power prices are up across the board (some pullback in early 2022 but still robust increase). For example, PJM (W) 2023 pricing is now above $40/MWh, compared with $25-$30/MWh in the two years through first half 2021. ERCOT North on-peak prices saw a similar lift to about $45/MWh for 2023 from $28/MWh in January, a year ago.

We now expect 2022 to see less power price backwardation compared to our expectations in 2021. Moreover, with ERCOT still showing load growth and winters in New England typically straining fuel supplies, we expect to see greater volatility in the power markets relative to the natural gas markets. We note that while power prices tend to be more volatile, spark spreads have remained relatively steady.

Nuclear generation is gaining traction in the de-carbonization dialogue. Regulators in the U.S. are more sensitive to the ability of nuclear units to deliver uninterruptible power and have approved zero emission credits (ZEC) revenues and carbon mitigation credits (CMC) revenues for some nuclear plants in Illinois, New York, and New Jersey.

Clean energy proposals have most support in the Biden administration's Build Back Better (BBB) plan and have the best chance of being included in a clean energy package. So far there has been little detail publicly available on specific provisions that would make it into a pared down version of BBB, though our conversations suggest that the current package of tax provisions for wind/solar and stand-alone battery tax credits, and nuclear PTC, will find traction and could be approved as proposed.

After the successful spin-off of Constellation Energy from Exelon Corp, consolidation in the nuclear industry is again a possibility, but perhaps unlikely in 2022.

Focus is shifted emphatically to firm power. Nuclear is gaining momentum, not just in the U.S. but also globally. In January 2022, the European Commission released new plans to include some natural gas and nuclear energy power plants as 'green' under the existing EU Taxonomy's Climate Change Mitigation objective. The inclusion of natural gas and nuclear power generation would likely provide some relief to Europe's volatile energy supply, especially as renewables are still scaling. It also appears that natural gas will play a larger role as a bridge fuel in oil majors transitioning to lower carbon intensity.

In the U.S., about 70% of the grid is 25 years or older and faces harsher weather conditions. With ERCOT's significant winter event in 2021, we think regulators will

increasingly consider the firmness of power delivery. All options for firming power are somewhat costly, whether a regional transmission organization chooses to invest in renewable energy with related storage and transmission, fuel infrastructure with long-term contracts, or further measures to reduce demand for wholesale electricity and natural gas. However, inaction also comes at a cost, including greater risks to reliability and higher emissions when it's more economical to burn oil than natural gas. In other words, a region can pay for its fuel-security risks periodically, in spiking wintertime prices and potential energy shortages, or it can pay the costs proactively and avoid reliability risks by investing in infrastructure, firming renewables, firmer fuel contracts, and other reliability incentives.

The grid is still transitioning and it's not quite there yet. Among clean, firm, cheap power, it appears that the choice is any two.

Renewable development could decline in 2022. Similar to 2021, we could see delays again in renewable build as supply chain issues remain unresolved, accentuating deliverability of components for renewable installations. Structural imbalances in the supply chain and the energy intensity and consumption controls that China imposed in late September 2021 have caused prices for a large number of photovoltaic (PV) module materials and components to rise.

A combination of factors has led up to this, including commodity inflation in polysilicon, steel, and copper that will continue to keep solar costs elevated, while steel and epoxy resin will result in wind turbine costs being high. As an example, polysilicon costs have about tripled over the last year, while prices for hot rolled steel have doubled. Equally, while freight costs have corrected modestly (20%), they are nowhere close to the pre-pandemic levels and are still about 400% elevated.

Installations will also be affected due to a prior withhold release order (WRO) on polysilicon from Xinjiang province, which is causing module delivery delays at ports (as customs takes longer to verify content origin). We expect WRO to improve by second half and resolve in 2022 as U.S. customs clears up backlog. We also expect new non-China module manufacturing capacity to come online but still expect polysilicon, steel and freight costs to drive the inflation narrative for solar panels.

To be clear, we expect demand for PV panels to increase but installations could lag because of supply cost escalations and disruptions. For 2022, market consultant InfoLink projects that the global solar module demand will range around 200-210 GW, up about 20% over 2021 levels.

Batteries scaling will matter in 2022. Across multiple markets, we expect to see battery storage adoption at an accelerating rate in light of growing grid reliability concerns. Statewide, this will be driven by:

- California: Solar and storage opportunity given resource adequacy concerns
- Illinois: Incentives for coal-to-solar-and-storage programs
- Texas: Merchant returns driven by a volatile energy-only market

We see benefits going to companies such as Vistra Energy with existing transmission interconnections in California and the ability to repower legacy fossil sites with renewables plus storage in Illinois. We particularly view California as a robust growth market given RA initiatives in the state, with the opportunity for solar addition/expansion at legacy assets.

While there is a growing critical mass around manufacturing, assembling, and integrating battery projects, we still see weak economics and returns without a stand-alone storage ITC, as previously expected under the BBB.

Alberta IPPs continue to benefit from robust electricity prices. The dynamics that resulted in strong power prices in 2021 in Alberta are likely to continue in 2022. This is beneficial for power producers with large merchant exposure to this market, namely

Capital Power Corp. (CPC; BBB-/Stable/--) and TransAlta Corp. (TAC; BB+/Stable/--). Power pool prices in 2021 have averaged about C$100 per megawatt-hour (C$/MWh), which is materially higher than the C$45/MWh average of 2020. The stronger prices were largely attributable to lower supply, as facilities were taken offline to undergo their conversion from coal to natural gas fueled. We anticipate this continued dynamic of restricted supply and modest load growth will support strong prices until the projected supply pipeline comes online materially by mid-decade. By then, power prices should decline as the more efficient converted facilities, combined with the broader renewable penetration, will be responsible for most of the generation. There could also be increased volatility if the less-efficient facilities are occasionally required to dispatch.

At the same time, we see regulatory risks as potentially increasing, given the government long-term goal of reducing greenhouse gas emissions 40%-45% below 2005 levels by 2030. A more stringent regulatory environment could have different implications for TAC and CPC, depending on their ultimate fleet and capabilities. As an example, TAC recently cancelled their large repowering project for Sundance 5, while CPC is moving forward with their repowering project for Genesee 1 and 2.

Regarding the other IPPs that we cover with large Canadian exposure, we anticipate they will continue to grow internationally through greenfield development and acquisitions. Having broader geographic and asset diversity could be credit positive, especially for renewable assets as it helps mitigate resource risks. As an example, Northland Power Inc. (BBB/Stable/--) has a robust development pipeline, which includes offshore wind in Europe and Asia.

Credit metrics and financial policy

We expect ratios to be weaker than levels we expected in 2021, partly because several companies faced weather events that have slowed deleveraging plans. However, we note that debt reduction is still a stated objective for a number of IPPs. Two years ago, expectations for aggregate debt/EBITDA and FFO to debt were above 4.0x and 15%, respectively. Now, some IPPs have targets of adjusted det to EBITDA in the 2.5x-3.0x range and adjusted FFO to debt above 25% on a sustained basis. However, the timeline has slipped to 2023.

Key risks or opportunities around the baseline

1. Focus on cost reductions and deleveraging

Storage solutions will eventually minimize volatility in the marketplace and reduce competitive barriers. As a result, we expect companies that seek to improve their credit profile would continue to cut costs and incrementally delever.

2. Divergence in strategies

Business simplification and streamlining will be the key for 2022. We ultimately see the emerging pure-play theme as sustaining with companies increasingly diversifying to gain exposure to electrification, retail, hydrogen, or renewable themes. Some companies will engage in opportunities like data centers and cryptocurrency-related load growth, potentially riskier because of counterparty exposure.

3. Capital allocation decisions will be key

Frustrated with languishing valuations, some IPPs have announced deployment of free cash flow for share repurchase programs. If these companies underperform, they would have the ability to reallocate capital to maintain financial ratios. Their willingness to reallocate capital is key to maintaining rating.

4. Environmental, social, and governance (ESG) risks

The industry continues to face potential clean air and water rules and continued exposure to carbon-based emissions. Social risks pertain to impact on communities on closure of assets. Conversion of assets or asset retirement obligations may also result in financial costs that need to be funded and could contribute to somewhat weaker financial measures.

Build Back Better. A key driver for the sector is the prospect for the passage of the Build Back Better Act, or an alternative legislation focused on the clean energy sector during 2022. While there is general support in the U.S. Senate for the current package of tax provisions for wind/solar tax credits, nuclear PTC, and emerging clean energy technologies, the reality for its passage, ahead of competing election legislation, could be more challenging.

To recall, the solar ITC was originally scheduled to decline from 30% in 2019 to 26% in 2020, 22% in 2021, and then stay flat at 10% in 2022. A relief bill approved by Congress in Dec. 2020 extended the 26% ITC available for solar projects that begin construction prior to Jan. 1, 2021, by two years, allowing the 26% ITC for projects that begin construction before Jan. 1, 2023. The 22% credit would then be available for projects that begin construction before Jan. 1, 2024. Projects slipping past 2024 qualify for only a 10% ITC. The placed-in-service deadline was similarly pushed back, with an ITC greater than 10% only available for projects that are placed in service before Jan. 1, 2026.

Importantly, while an extension provides a boost to deployments, with overnight capital costs projected to decline from $1,250/KW and $1,150/KW for wind and solar, respectively, in 2020 to $1,050/KW and $825/KW in 2025, we expect renewables deployment to continue to accelerate in the medium term as they become competitive without subsidies.

Related Research

- Decarbonization Efforts Are Shaking Up Global Energy Markets, Sept. 28, 2021
- The Energy Transition: Offshore Wind Picks Up, Sept. 20, 2021
- Industry Top Trends Update: Unregulated Power North America, July 15, 2021
- Without Firm Power, U.S. Independent Power Producers' Credit Could Soften, April 5, 2021

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