

# 2022

## State of the Markets

A Staff Report to the Commission

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March 16, 2023



FEDERAL ENERGY REGULATORY COMMISSION  
Office of Energy Policy and Innovation  
Division of Energy Market Assessments

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# PREFACE

The State of the Markets report, prepared by the Office of Energy Policy and Innovation's Division of Energy Market Assessments, summarizes key trends in electricity and natural gas markets, important topics, and notable developments in 2022. The first section of the report summarizes key fundamentals and developments in the natural gas and electricity markets, while the second section describes infrastructure changes, including the shift to renewable resources. The report concludes with a section on major events that occurred in 2022, including the western heat wave and its effect on electricity and natural gas markets, along with the December 2022 winter storm, as notable weather events.

## KEY FINDINGS

In 2022, nationwide, most generation capacity additions came from wind and solar resources and most retirements came from coal resources. While the shares of generation from wind and solar made gains, natural gas held the largest share of generation at 38.9% in 2022. Natural gas capacity additions and battery storage additions were behind those of wind and solar. In 2022, energy markets continued to transition away from fossil fuels towards renewable resources. The amount of power sold from distributed energy resources (DERs) continued to grow at a slow rate. Wholesale electricity market arrangements grew in 2022. The Southeast Energy Exchange Market (SEEM), a platform to facilitate bilateral trades, was launched in the southeast and more participants joined the Western Energy Imbalance Market (WEIM) and the Western Energy Imbalance Service (WEIS).

More new generating resources requested interconnection to the grid. As of end of 2022, over 1,850 GW of capacity (including storage) were pending in transmission providers' interconnection queues, with wind, solar, and storage making up 94% of this capacity. These resources continued to encounter delays in transmission providers' interconnection queues, and many will likely face additional challenges such as the need for costly transmission network upgrades. More line-related transmission projects entered service in 2022. Like prior years, most new line-related transmission projects entering service were driven by reliability needs and aging infrastructure, dwarfing the number of projects driven by economic benefits, public policy needs, or new generation. A few transmission providers conducted forward-looking studies in 2022 to identify transmission requirements needed due to new generation and load-forecast growth. Recognizing the challenges of interconnection queue delays and the need for longer-term transmission planning, the Commission in 2022, issued two Notice of Proposed Rulemakings (NOPR) to address issues associated with existing generator interconnection and regional transmission planning processes.<sup>1</sup>

Wholesale electricity prices increased in most markets (U.S. pricing hubs) in 2022 for the second consecutive year, with limited exceptions, above their pre-pandemic levels. Among the organized markets, New York ISO (NYISO) Zone J (New York City) and PJM Interconnection (PJM) saw the largest mean wholesale price increases – over 80%. Electricity demand grew in every regional transmission organization or independent system operator (RTO/ISO) as economic activity continued to rebound from the COVID-19 pandemic and weather had an increased impact on heating and cooling demand at times. Various factors including higher electricity demand and higher natural gas prices placed upward pressure on wholesale electricity prices in 2022.

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1 Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, NOPR, 179 FERC ¶ 61,028; Improvements to Generator Interconnection Procedures and Agreements, NOPR, 179 FERC ¶ 61,194.

The national average benchmark natural gas spot price at Henry Hub rose to \$6.38/Million British thermal unit (MMBtu) – its highest level since 2008 – as heightened geopolitical risk drove up forward-looking risk expectations in the U.S. natural gas market year-over-year in 2022. The Russian invasion of Ukraine in February 2022 and its fallout, including the cut-off of natural gas supplies from Russia to Europe initiated in August 2022, disrupted global oil and gas markets, particularly liquified natural gas (LNG) markets. Nonetheless, the natural gas spot price at Henry Hub dropped from its highest quarterly price of \$7.96/MMBtu in the third quarter down to \$4.60/MMBtu in the fourth quarter partly driven by a milder-than-anticipated winter along with natural gas production reaching record highs around the fourth quarter. U.S. LNG exports grew in 2022, though at a slower pace than they did in 2021.

Other fuels such as jet fuel and propane saw prices rise significantly in 2022, as crude oil prices increased from 2021 to 2022. The increase in crude oil prices was not only steered by the Russia-Ukraine conflict but also by the Organization of the Petroleum Exporting Countries' (OPEC) oil production cuts in November 2022 and limited domestic crude oil production growth in 2022.

Extreme weather stressed the power grid in 2022. From August 31 through September 9, 2022, record-setting heat in the western United States drove electricity demand in both the Western Interconnection (WECC) and California Independent System Operator (CAISO) to an all-time high. Despite the heat wave, CAISO maintained uninterrupted system operations because of market and procedural enhancements put in place after summer 2020. Notably, CAISO utilized flexible resources, including battery storage resources, during critical peak hours and undertook enhanced coordination with regional utilities to maintain system operations through the western heat wave. CAISO's ability to maintain uninterrupted operations during the western heat wave demonstrated that safeguards can be instituted to help power systems withstand extreme and prolonged spikes in demand. Nevertheless, challenges to resource adequacy persist, as fossil-fuel-based generating facilities continue to retire while an unprecedented number of interconnection requests has led to increasing lead times and uncertainty in the interconnection process.

On December 23-25, 2022, a winter storm, another extreme weather event, increased electricity demand across the mid-continental and eastern United States just as low temperatures constrained the production and supply of natural gas. The winter storm triggered power outages affecting consumers, predominantly in Southeast states, including North Carolina and Tennessee. On December 28, FERC and North American Electric Reliability Corporation (NERC) initiated a joint inquiry into the bulk power system operations during the winter storm. The joint inquiry seeks to identify performance issues and, where appropriate, recommend solutions to address those issues. Given the impact of extreme weather events on system reliability and Commission-jurisdictional rates, in 2022, FERC initiated two rulemakings aimed at improving the reliability of the bulk power system against the threats of extreme weather.

## MARKET DEVELOPMENTS

This section summarizes key fundamentals and developments in the natural gas and electricity markets. For natural gas, the section discusses the natural gas prices at market hubs, production levels across conventional and shale basins, and demand by sector. This section also covers natural gas storage, imports and exports, and trading. For electricity markets, this section discusses wholesale electricity prices by market, electricity generation by resource type, and resource capacity additions and retirements by region. The section also includes a discussion on

RTO/ISO capacity markets, electricity demand, and ends with a brief review of recent expansions of market arrangements. For other market developments, this section provides a review of macroeconomic and geopolitical risk factors impacting the crude oil and LNG markets in 2022, major credit trends and credit-stress events in organized electricity markets and fuel markets, and jet fuel and propane market fundamentals, including inventories and exports.

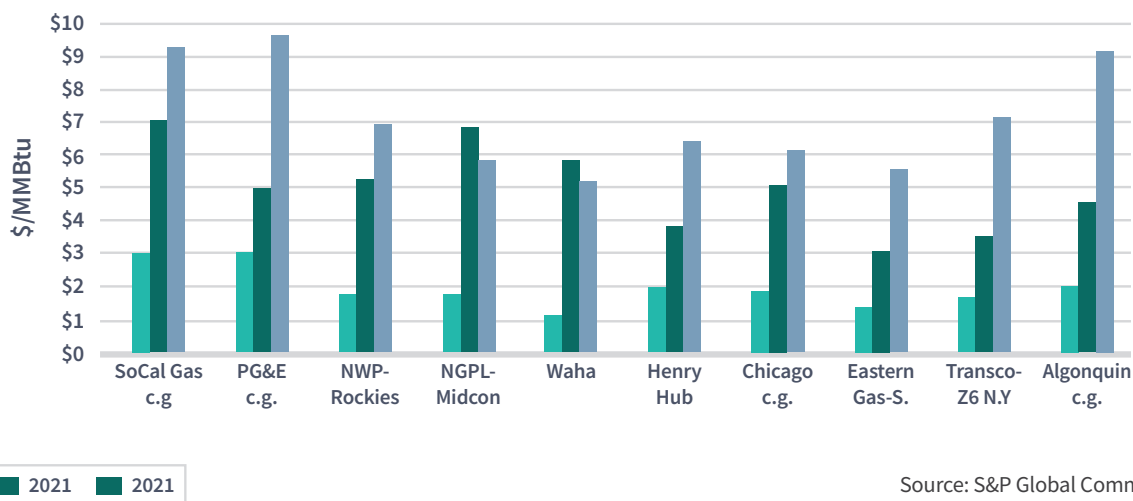
## Natural Gas Market Fundamentals

Natural gas prices increased in 2022, as natural gas demand growth outpaced gains in natural gas production. In 2022, natural gas demand was driven by increased domestic natural gas consumption and LNG exports. Although production did not keep pace with demand, it continued the growth trend seen in the last decade. Production highs were especially noticeable in the Permian and Haynesville Basins. Pipeline infrastructure expansions increased the takeaway capacity from both basins. In contrast, production decreased year-over-year in the Marcellus Basin and the Utica basin likely in part disincentivized by limited takeaway capacity additions. Natural gas storage inventories continued to trend downwards in 2022 consistent with declines in storage levels that have been present in the market in recent years.

### NATURAL GAS PRICES

Natural gas spot prices throughout most of the United States increased from 2021 to 2022. Most natural gas hubs saw price gains on top of already significant price increases in 2021 (see Figure 1).

**Figure 1: Average Spot Natural Gas Price at Select U.S. Hubs**



Source: S&P Global Commodity Insights

In 2022, the Henry Hub national benchmark spot price averaged \$6.38/MMBtu, up from \$3.82/MMBtu in 2021. This was the highest average spot price at Henry Hub since 2008, and the largest absolute year-over-year average price increase since 2005. The spot price at Henry Hub was highest in the third quarter of the year, averaging \$7.96/MMBtu. By contrast, the price averaged \$4.60/MMBtu in the first quarter, and \$5.55/MMBtu in the fourth quarter.

A variety of interrelated factors such as weather, storage levels, production and demand can influence natural gas prices. Warmer-than-normal temperatures across much of the country during the summer of 2022 increased natural gas demand. Low natural gas storage inventories exiting winter 2021-22 were slowly refilled over the summer, due to high natural gas prices and price volatility.<sup>2</sup> Uncertainty about natural gas demand for LNG exports significantly contributed to price volatility in 2022.<sup>3</sup> Natural gas storage inventories, demand, and LNG exports are discussed in later sections of this report.

Two California hubs, SoCal Gas Citygate outside Los Angeles and PG&E Citygate near the Bay Area, saw some of the highest average spot prices in 2022, as shown in Figure 1. SoCal Gas Citygate averaged \$9.26/MMBtu, up \$2.27/MMBtu from 2021, and PG&E Citygate averaged \$9.63/MMBtu, an increase of \$4.67/MMBtu. Both hubs, and prices across the western United States, were closely aligned with Henry Hub prices for most of 2022 until the beginning of November, when they increased disproportionately relative to Henry Hub and the eastern United States. The high prices continued through December, peaking at \$49.68/MMBtu at SoCal Citygate for December 14 and \$57.07/MMBtu at PG&E for December 22. According to EIA, several simultaneous events contributed to high prices including widespread below-average temperatures, high natural gas consumption, reduced natural gas imports from Canada, pipeline constraints including maintenance in West Texas that reduced natural gas flowing west, and low natural gas storage levels throughout the Pacific region. These events contributed to significant separation between average natural gas prices and median prices at the SoCal Citygate and PG&E Citygate hubs.

Algonquin Citygates, a Boston area hub, also experienced higher prices, averaging \$9.15/MMBtu in 2022. Prices were particularly high during cold weather events. Due to constrained pipeline capacity into New England, segments of the region's pipelines often reach their maximum capacity in wintertime.<sup>4</sup> Prices at Algonquin Citygates frequently reflect winter scarcity as well as the region's reliance on LNG imports to supplement pipeline supplies. As global demand for LNG increased, natural gas prices in New England also rose, reflecting the effects of the tight international market on the region. In late summer, prices were especially high in the futures market for Winter 2022/2023 delivery likely due to the expected need for New England to compete with Europe for LNG cargos. The Transco Z6 N.Y. hub outside of New York City is also affected by these issues, albeit less acutely. Prices at Transco Z6 N.Y. averaged \$7.09/MMBtu in 2022, up \$3.61/MMBtu from 2021. Because natural gas prices were much higher for several days than the rest of the year at SoCal Gas Citygate, PG&E Citygate, Transco-Z6 NY, and Algonquin Citygates, the median natural gas price was below 90% of the mean price at each of these hubs as the mean is more sensitive to outliers than the median is.

In contrast to the generally higher natural gas price trends, some supply and pipeline trading locations had declining year-over-year prices amid rising production and different market dynamics from 2021. For example, NGPL-Midcontinent, which starts in the Texas Panhandle and extends to Nebraska, and Waha in west Texas, had slightly lower average spot prices in 2022 as compared to 2021. NGPL-Midcontinent average spot prices were \$5.79/MMBtu in 2022, \$1.01/MMBtu lower than in 2021. However, although annual, average prices were relatively lower, NGPL-Midcontinent's region was one of the areas most affected by the February 2021 winter storm and saw prices exceeding \$200/MMBtu for five days that month.

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2 U.S. EIA. Natural Gas Weekly Update. July 6, 2022. [https://www.eia.gov/naturalgas/weekly/archivenew\\_ngwu/2022/07\\_07/](https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/07_07/)

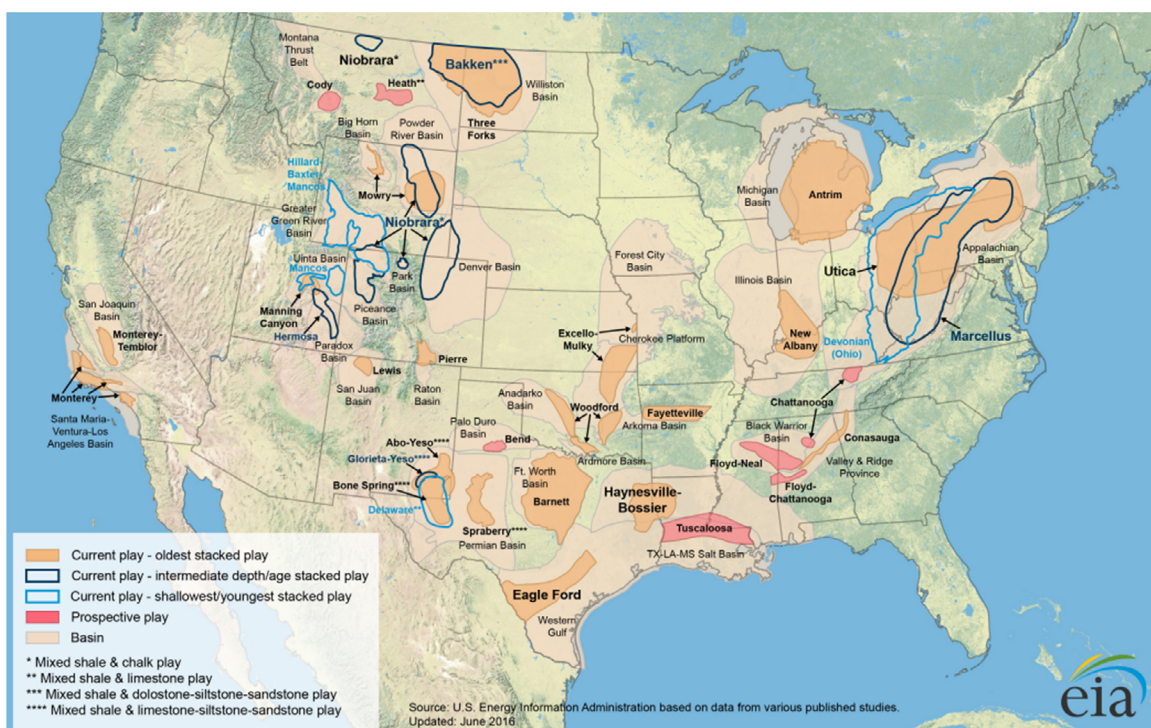
3 U.S. EIA. Today in Energy. August 24, 2022. <https://www.eia.gov/todayinenergy/detail.php?id=53579>

4 Key pipeline segments in New England frequently exceeded 95% utilization and at times during the winter these segments reached or exceeded their maximum capacity.



Waha hub prices averaged \$5.18/MMBtu, down \$0.62/MMBtu from 2021. At Waha this year, spot natural gas prices were briefly negative. In October and December 2022, pipeline maintenance caused pipeline constraints, which limited natural gas pipeline takeaway capacity, that contributed to a total of four days of negative spot prices.<sup>5</sup> Negative prices were more common at Waha prior to 2020, due to limited natural gas pipeline takeaway capacity combined with gas production that had increased due largely to associated gas from oil-focused drillers. Since the completion of additional pipeline capacity in the region, the negative prices became less common and did not occur at all in 2021.

**Figure 2: Lower 48 States Shale Basins**



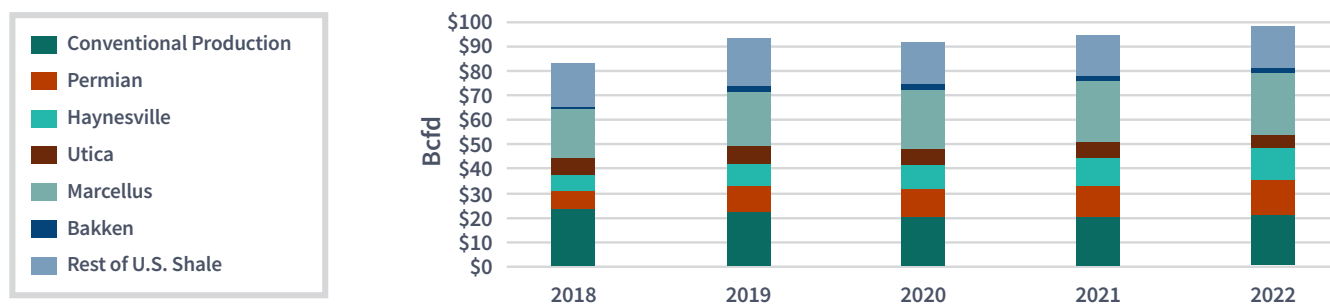
Source: U.S. EIA

## NATURAL GAS PRODUCTION

Record natural gas production in 2022 continued the growth trend seen in the last decade, except for the 2020 COVID-19 related decrease in production. U.S. dry natural gas production increased 3.52 Billion cubic feet per day (Bcfd) year over year, averaging 98.09 Bcfd in 2022. In 2021, U.S. natural gas production was 94.57 Bcfd, a 3.06 Bcfd increase from 2020. However, during 2020 production declined by 1.36 Bcfd as compared to 2019. Monthly natural gas production reached record highs in 2022, averaging above 100 Bcfd in September, October, and November. Production highs were especially noticeable in the Permian Basin, in western Texas and southeastern New Mexico, and Haynesville Basin, in northwest Louisiana and East Texas. The Permian Basin reached a record monthly rate of 16.19 Bcfd in September 2022 and averaged 15.37 Bcfd for the entire year, an increase of 2.01 Bcfd as compared to 2021. Production in the Haynesville Basin reached a record monthly high of 14.11 Bcfd in December 2022 with an annual average of 13.16 Bcfd in 2022, an increase for the year of 2.05 Bcfd. Pipeline infrastructure expansions in

5 Argus Media. Waha spot gas prices negative for a second day. October 26, 2022. <https://www.argusmedia.com/en/news/2384618-waha-spot-gas-prices-negative-for-a-second-day>

**Figure 3: Dry Natural Gas Production**



Source: U.S. EIA

both the Permian and Haynesville Basins facilitated the increases in production.<sup>6</sup> In comparison, production in the Marcellus Basin, located in the Appalachian Basin, declined 0.20 Bcfd year-over-year in 2022, the first year-over-year decline in a decade, in line with limited pipeline capacity additions.<sup>7</sup> Similar, production in the Utica Basin, also in the Appalachian Basin, declined 1.36 Bcfd in 2022 compared to 2021.

From 2018 to 2022, increases in natural gas production result largely from production in shale formations Permian, Marcellus, and Haynesville (see Figure 3). The growth in infrastructure for transporting and processing natural gas liquids has facilitated growth in natural gas production in the Permian Basin.<sup>8</sup> Figure 4 shows U.S. natural gas production by various shale formations.

**Figure 4: Dry Natural Gas Production by Formations (Bcfd)**

Year	Conventional Production	Permian	Haynesville	Marcellus	Utica	Bakken	Rest of U.S. Shale	Annual Total
2018	23.3	7.4	6.9	19.7	6.8	1.5	18.8	84.3
2019	22.6	10.2	8.9	22.2	7.6	1.9	19.5	92.9
2020	20.2	11.6	9.6	23.8	7	1.9	17.5	91.5
2021	19.5	13.4	11.1	25.4	6.3	2.2	16.7	94.6
2022	20	15.4	13.2	25.2	5	2.2	17.2	98.1
<b>Percentage of Total 2022 Production</b>	<b>20%</b>	<b>16%</b>	<b>13%</b>	<b>26%</b>	<b>5%</b>	<b>2%</b>	<b>18%</b>	<b>N/A</b>
<b>Change in Production Between 2021 and 2022</b>	<b>3%</b>	<b>15%</b>	<b>18%</b>	<b>-1%</b>	<b>-21%</b>	<b>1%</b>	<b>3%</b>	<b>N/A</b>

Source: U.S. EIA

6 U.S. EIA, U.S. Dry Natural Gas Production Set Monthly Records In 2022; We Forecast An Annual Record, December 9, 2022, <https://www.eia.gov/todayinenergy/detail.php?id=54959>

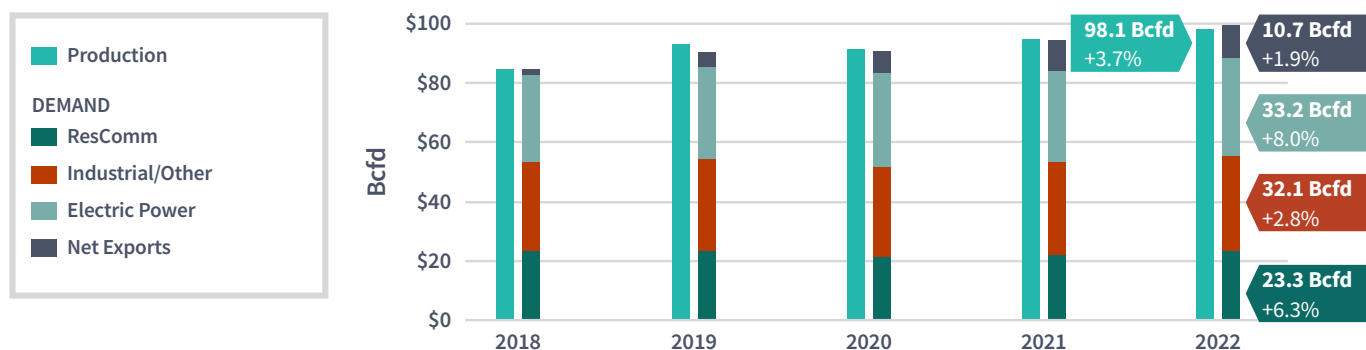
7 U.S. EIA, Most U.S. Gross Gas Withdrawals And Production Growth Occurred In The Appalachia, Permian, And Haynesville Regions In 2021, March 24, 2022, [https://www.eia.gov/naturalgas/weekly/archivenew\\_ngwu/2022/03\\_24/](https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/03_24/)

8 U.S. EIA, New Pipelines Carrying Natural Gas Plant Liquids Increase Natural Gas Processing, March 2, 2022, <https://www.eia.gov/todayinenergy/detail.php?id=51458>

## NATURAL GAS DEMAND

Economic recovery from COVID-19 contributed to overall growth in natural gas demand, which outpaced growth in natural gas supply, as seen in Figure 5. Total U.S. natural gas demand in 2022 averaged 99.2 Bcfd, 4.8 Bcfd or 5.0% higher than total 2021 natural gas demand, and 12.2 Bcfd or 14.0% higher than the previous five-year average. Residential and commercial demand increased by 6.3% in 2022 whereas industrial and other<sup>9</sup> demand increased by 2.8%. Natural gas consumed for electricity generation, or power burn, saw the largest year-over-year increase in natural gas demand increasing 7.9%.

**Figure 5: Natural Gas Production and Demand by Sector**



Source: U.S. EIA

In total, domestic natural gas consumption (which excludes net exports) increased 5.6% from the prior year, averaging 88.6. This is the highest domestic consumption since 2018. Domestic consumption in 2022 increased in all sectors.

In 2022, power burn averaged 33.2 Bcfd, which represented a 7.9% increase from power burn of 30.8 Bcfd in 2021. The increase is a result of above-normal temperatures, reduced coal-fired electricity generation, and recent natural gas-fired electricity generation capacity additions. This increase follows a 3.2% decrease in power burn from 2020 to 2021. The share of U.S. electricity generation from natural gas in 2022 was 38.8%, up from 37.3% in 2021.

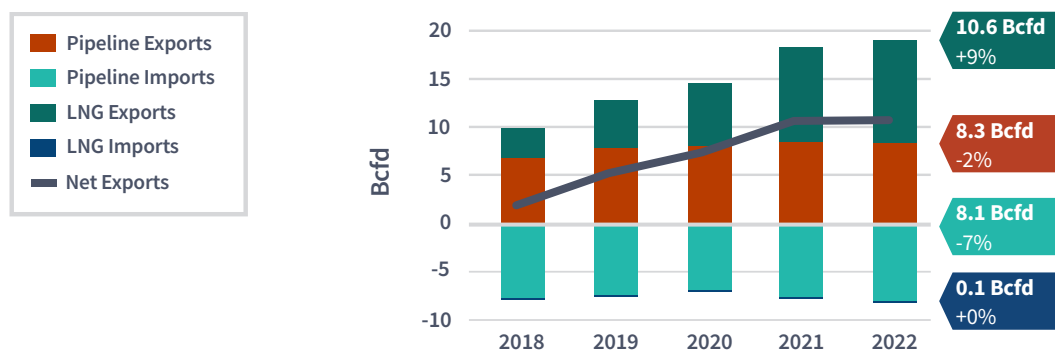
## NATURAL GAS IMPORTS AND EXPORTS

U.S. natural gas net exports rose in 2022, albeit at a slower pace than in 2021. In 2022, net exports of natural gas averaged 10.6 Bcfd in 2022, up 0.6% from 10.5 Bcfd in 2021, as seen in Figure 6. Gross exports of natural gas, including LNG and pipeline exports, averaged 18.9 Bcfd in 2022, a 3.6% increase from 18.2 Bcfd in 2021. Gross imports, including LNG and pipeline imports, averaged 8.3 Bcfd in 2022, a 7.7% increase from 7.7 Bcfd in 2021. The growth in U.S. natural gas net exports is largely driven by LNG exports, which averaged 10.6 Bcfd in 2022, an 8.6% increase from 9.8 Bcfd in 2021 as European markets significantly increased their purchase of imported LNG from the constrained global supply chain following the Russian invasion of Ukraine.

<sup>9</sup> Pipeline use, distribution use, and vehicle fuel.



**Figure 6: U.S. Natural Gas Imports and Exports**

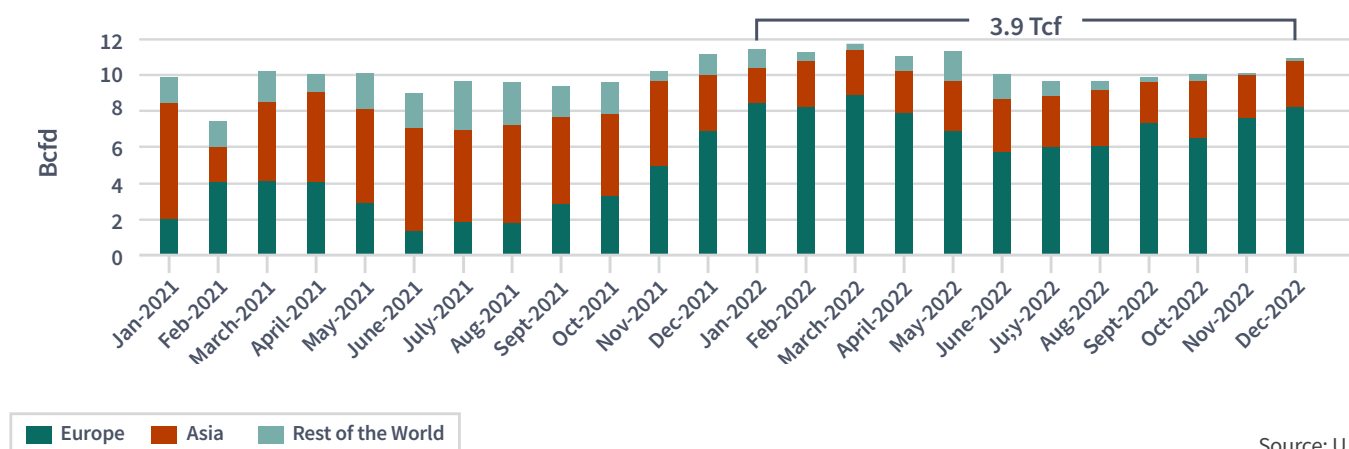


Source: U.S. EIA

In 2022, more global LNG demand could be fulfilled as major regasification capacity increased. Tight LNG supplies contributed to increasing international prices, which reached record levels, incentivizing U.S. LNG exports. The approval and expansion of multiple LNG export facilities in 2022 increased LNG liquefaction capacity to serve the growing international LNG demand to higher-priced regions.

To offset a decline in Russia's natural gas pipeline exports to Europe and high LNG prices, U.S. LNG exports increased to the region. S&P Global's LNG spot prices in Europe (United Kingdom, Belgium, and Spain) increased by 106% year-over-year on average and LNG spot prices in Asia (India, China, Japan, and South Korea) increased by 82% year-over-year on average, with both continents paying nearly \$34/MMBtu in 2022 on average. In 2022, the United States exported 3.9 trillion cubic feet (Tcf) to 38 countries via vessels, with the most LNG volumes being delivered to France. Nearly 48% of all U.S. LNG exports were delivered to four countries in 2022 with 571 billion cubic feet (Bcf) to France, 464 Bcf to the United Kingdom, 426 Bcf to Spain, and 378 Bcf to the Netherlands. Year-over-year, U.S. LNG exports to China declined by 78%, Japan declined by 40%, and South Korea declined by 36%. By region, the United States exported 66% of total LNG volumes to European markets and 23% to Asian markets in 2022.

**Figure 7: Monthly U.S. LNG Exports by Destination Region**



Source: U.S. EIA

**Figure 8: Changes in International LNG Spot Prices**

\$/MMBtu	Europe	Asia
Year-Over-Year Increase on Average	106%	82%
Average Price	\$34	\$34
% of Total LNG Volumes	66%	23%

Source: S&P Global Market Intelligence

An unplanned outage at the Freeport LNG's natural gas liquefaction plant on the Gulf Coast in South Texas on June 8, 2022, through February 11, 2023, reduced LNG export capacity in the United States by approximately 2 Bcfd (approximately 15% of the U.S. LNG export capacity at the time of the outage). This decrease in liquefaction capacity coincided with significantly tight LNG markets and volatile domestic market prices.

The United States has added 2.34 Bcfd of FERC-authorized export capacity in 2022, with Train 6 at the Sabine Pass LNG export facility adding 0.76 Bcfd of export capacity and Venture Global LNG's Calcasieu Pass adding 1.6 Bcfd of export capacity. As of December 2022, the FERC authorized export liquefaction capacity in the United States, which includes uprates to LNG production capacity at Sabine Pass and Corpus Christi, is 14.0 Bcfd across 7 LNG export facilities. Additionally, several LNG projects, including Corpus Christie Stage 3, Golden Pass, and Plaquemines Phase 1, are currently under construction and will add 5.6 Bcfd to U.S. LNG export capacity.

Gross pipeline exports of natural gas averaged 8.3 Bcfd in 2022, a decrease of 2.1% from 8.5 Bcfd in 2021. In 2022, natural gas pipeline exports to Mexico decreased 3.7% to average 5.7 Bcfd and exports to Canada decreased 1.6% to average 2.6 Bcfd. Natural gas exports to Canada are generally regional transfers in the Midwest and Northeast that often net larger imports into the United States from Canada. In Mexico, the electricity sector and (to a slightly lesser degree) the industrial sector have led natural gas consumption growth in recent years. Much of this growth has been met by growth in pipeline imports from the United States.

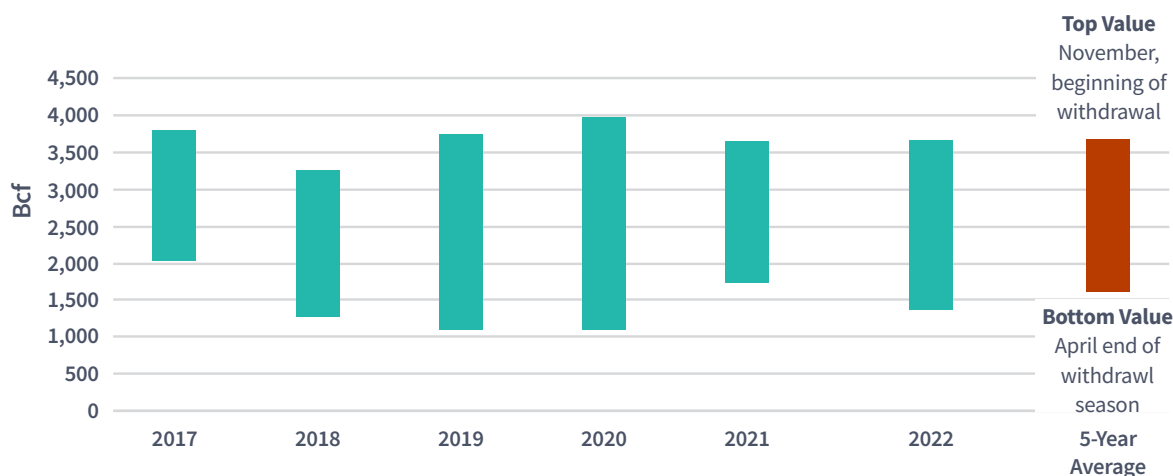
Despite the growth in gross natural gas exports, imports remain a vital part of the U.S. supply mix, especially during times of high demand. With virtually no pipeline imports into the United States from Mexico, gross U.S. natural gas imports were primarily driven by Canada, accounting for 8.3 Bcfd on average in 2022, an increase of 7.7% from 7.7 Bcfd in 2021. Most of the natural gas the United States imported from Canada originated in Western Canada and was shipped to U.S. markets in the West and Midwest regions. In addition to pipeline imports, LNG imports play a meaningful role in supplying the market—particularly in New England—during winter months. Although LNG import volumes into the United States in 2022 only averaged 0.06 Bcfd, LNG import volumes in January and February of 2022 were triple the average, at 0.18 Bcfd.

## NATURAL GAS STORAGE

Natural gas storage inventories help to balance natural gas demand and supply and are fundamental to price formation. As shown in Figure 9, natural gas storage levels have trended downwards over the last three years, with storage levels at the end of withdrawal season falling from 1,986 Bcf in 2020 to 1,382 Bcf in 2022. Comparing the ten-year and five-year averages for the end of withdrawal season, the average for the end of withdrawal season has decreased by approximately 60 Bcf. End of withdrawal season storage levels had been on a downward trajectory from 2017 through 2019 but recovered slightly in 2020 during the COVID-19 pandemic. Total withdrawals for winter 2021/2022 equaled 2,262 Bcf, 7% above the five-year average and 2% above winter 2020/2021..<sup>10</sup>

<sup>10</sup> We define winter withdrawals for a season as the difference between the maximum amount in the first calendar year and the minimum amount in the subsequent calendar year.

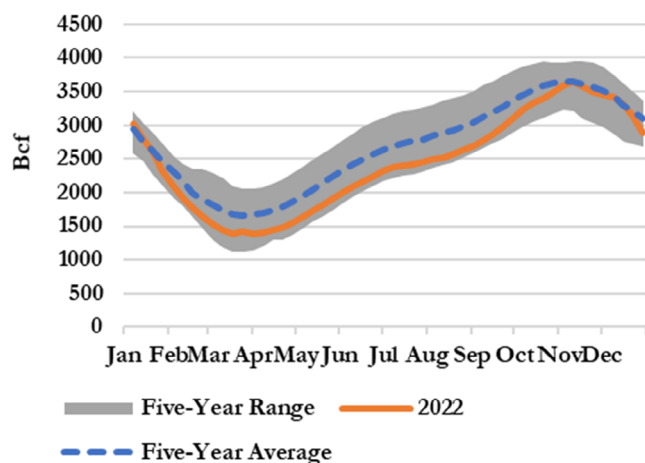
**Figure 9: Natural Gas Storage Inventories**



Source: U.S. EIA

Storage levels in the Pacific region reached their highest levels for 2022 in late July/early August of 2022, unlike the rest of the United States which peaked in November. This was due to a heat wave that the Pacific Northwest experienced in late August. Storage levels did not recover to their previous levels after the withdrawal in August. At the beginning of November 2022, storage levels in the Pacific region were 15% below the five-year average for that time of year. By the last week of December, storage levels in the Pacific region were 33% below the five-year average for that time of year. Adding to low storage levels in the Pacific region was the reclassification of 51 Bcf of working gas to base gas<sup>11</sup> in Pacific Gas and Electric (PG&E) that occurred in June of 2021.

**Figure 10: U.S. Lower 48 Natural Gas Storage Inventories**

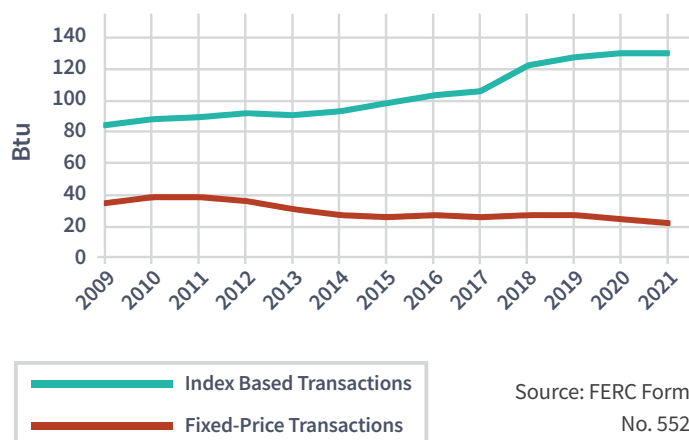


Source: U.S. EIA

Underground storage inventories finished the withdrawal season in April 2022 at 1,382 Bcf, 253 Bcf or 15% below the five-year average. Injections—defined as the difference between the lowest and highest amounts of natural gas in storage in a calendar year—for 2022 equaled 2,262 Bcf, 19% above 2021 injection levels. In November 2022, at the beginning of the 2022-2023 withdrawal season, natural gas storage levels were at 3,644 Bcf, which is 30 Bcf or 1% below the five-year average. Natural gas storage levels finished the 2022 calendar year at 2,891 Bcf, representing 753 Bcf in withdrawals through the first two months of the 2022/2023 withdrawal season. Figure 10 shows the five-year range, the five-year average, and storage levels in 2022.

11 According to EIA, base gas (or cushion gas) is the volume of natural gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates. Working gas capacity refers to total gas storage capacity minus base gas. Working gas is the volume of gas in the reservoir above the level of base gas, which is available to the marketplace.

**Figure 11: Natural Gas Trading Transactions**



## NATURAL GAS TRADING

The U.S. natural gas marketplace has a highly competitive spot, or cash, market where brokers and others buy and sell natural gas daily in short-term deals for next-day delivery. In addition, natural gas has active “bid week” markets where buyers and sellers arrange for the purchase and sale of physical natural gas to be delivered throughout the coming month. Partial visibility into natural gas physical trading is available with the FERC Form No. 552, Annual Report of Natural Gas Transactions. In Form No. 552, market participants with physical trades in the reporting year equal to or greater than 2.2 trillion British Thermal Units (Tbtu) report whether those trades were index-priced or fixed-price transactions. Continuing a trend from recent years, the

ratio of index-priced natural gas trades to the fixed-price trades that set those indices continues to grow. This could indicate declining volume and liquidity in price setting trades at indexed trading locations.

Staff analysis of Form No. 552 data shows that, since 2009, the volume of trades based on price indices has grown while the volume of fixed-price trades used to calculate price indices has been declining. As seen in Figure 11, the total fixed price transactions reported to indices in 2021 has declined by 35% since 2009 while the total number of index-based transactions has risen by 54% since 2009. Staff estimates that in 2021 about 20.5 MMBtus of natural gas transactions were settled based on index prices for every one MMBtu bought or sold in the fixed-price or physical basis market and reported to price index developers.<sup>12</sup> This compares to 2020, for which staff estimated less than 15.7 MMBtus of index-settled transactions for every one MMBtu reported to price index developers.

The consistent decline in fixed-price trades being reported to indices led FERC to issue a revised price index policy statement<sup>13</sup> on April 21, 2022 to encourage more market participants to report their transactions to price index developers, provide greater transparency into the natural gas price formation process, and increase confidence in the accuracy and reliability of wholesale natural gas prices.

## Electricity Market Fundamentals

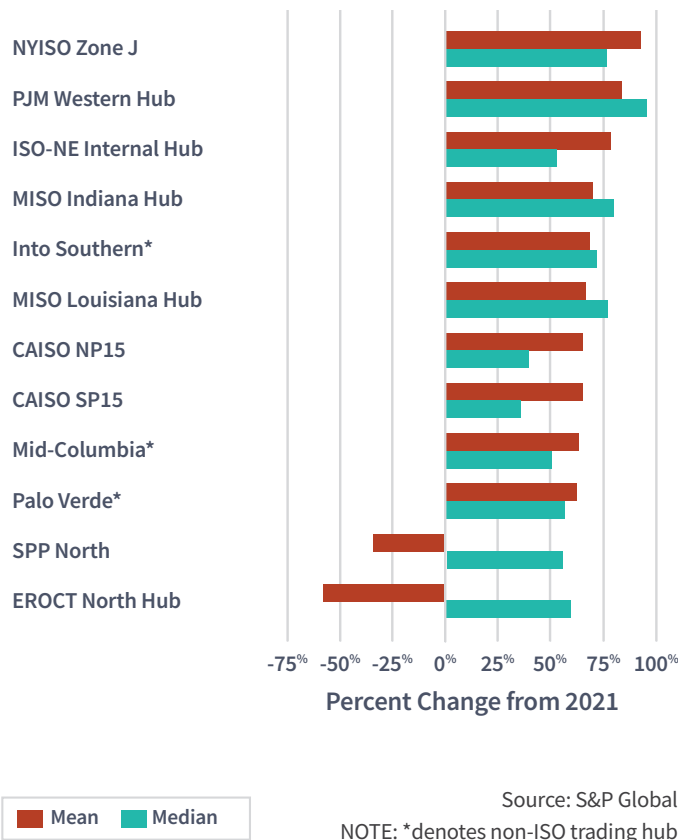
Wholesale electricity prices increased in 2022 for a second consecutive year, after two previous years of decline. Higher natural gas prices and increased electricity demand placed upward pressure on wholesale electricity prices. Longer-term trends in electric capacity continued, with new entry of natural gas-fired, wind, and solar resources while coal-fired generating units retired. Seasonal electricity prices also tracked prices for natural gas, as natural gas

<sup>12</sup> Platts and NGI both include fixed-price transactions from the InterContinental Exchange (ICE) to increase the liquidity of their price indices. Commission staff analysis of the estimated volumes reported to price index developers via the Form No. 552 does not include supplemental information from ICE.

<sup>13</sup> FERC, February 13, 2023, *Actions Regarding the Commission's Policy on Price Index Formation and Transparency, and Indices Referenced in Natural Gas and Electric Tariffs*

was typically the marginal fuel for electricity generation in most markets. Wholesale electricity market arrangements expanded in 2022 through the creation of the Southeast Energy Exchange Market (SEEM), and additional participants in the Western Energy Imbalance Market (WEIM) and the Western Energy Imbalance Service (WEIS).

**Figure 12: Change in Annual Mean and Median, Day-Ahead On-Peak Price, from 2021 for Select Nodes**



## WHOLESALE ELECTRICITY PRICES

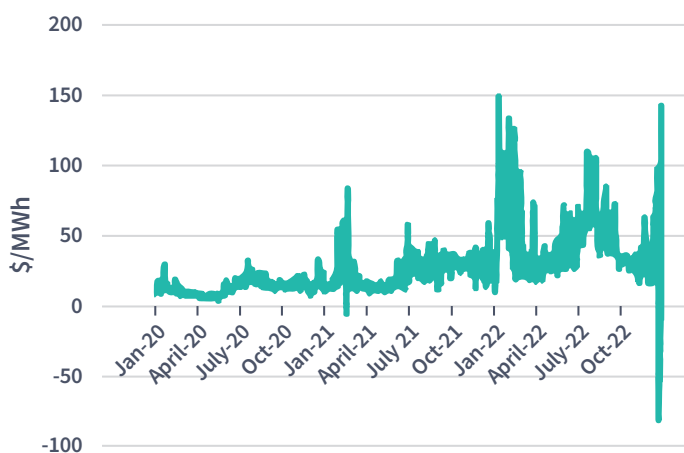
This section primarily focuses on mean wholesale day-ahead on-peak prices (herein referred to as mean wholesale electricity prices or wholesale electricity prices); however, median wholesale prices are informative as a measure of central tendency when extreme weather events, such as the February 2021 winter storm, cause significant increases in mean prices (see Figure 12).

Mean wholesale electricity prices increased the most at NYISO Zone J (New York City), where 2022 prices were 93% higher than in 2021. PJM also saw a significant price increase in 2022, with mean prices at the Western Hub increasing by 84%. Increases in Midcontinent Independent System Operator (MISO) were similarly high, with Indiana Hub prices increasing by 69% and Louisiana Hub increasing 66%, compared to the prior year.

Because wholesale electricity prices at the SPP North Hub and the ERCOT North Hub were significantly affected by the February 2021 winter storm, median prices rather than mean prices may provide better measures of central tendency for these hubs. While mean prices declined by 34% and 57% respectively year over year as a result of the high mean prices set in 2021, median prices at the SPP North Hub increased 55% in 2022 relative to 2021, while median prices at ERCOT North increased 59%.

Whereas 2021 saw higher wholesale electric prices early in the year and moderate prices in the summer in many markets, 2022 saw both elevated summer prices and a return to high prices in December. In CAISO, mean first quarter prices at the \$50 per megawatt hour (MWh) level increased to more than a \$100/MWh in the summer, before rising to record rates in December, with day-ahead on-peak prices at the hub SP-15, in California, consistently over \$250/MWh. These trends echoed natural gas prices at the SoCal Citygates pricing hub as discussed above. In MISO, SPP and PJM, wholesale electricity prices were lower in February due to the absence of extreme weather but were high during the summer, as lingering hot weather drove up demand. ISO New England (ISO-NE) and NYISO both had elevated prices in the first quarter due to heating demand, high summer prices due to cooling demand, and then a return to high prices in the fourth quarter as heating demand rose.

**Figure 13: New York City Spark Spread**



Source: Derived from S&P Global Platts data. Uses Transco Z6 NYC gas prices with Zone J Day-ahead electricity prices. Uses a heat rate of 7,000 Btu/kWh

These seasonal electricity prices also reflect the impact of increased natural gas prices. As discussed in the natural gas prices section, spot natural gas prices throughout the United States increased in 2022 relative to 2021. These higher fuel costs resulted in higher wholesale electricity prices because natural gas-fired generation clears the market price in most RTO/ISO markets. In particular, simultaneous demand for space heating and power burn during cold weather events can drive up natural gas prices, which in turn drive up wholesale electricity prices.

The strong relationship between natural gas prices and wholesale electricity prices can be demonstrated through the spark spread. A spark spread is the difference between the price received by a generator for electricity produced and the cost of the fuel. Thus, the higher the spark spread the more profitable a natural gas-fired plant will be. Spark

spreads echoed the increase in wholesale electricity prices in most markets, with spark spreads trending higher during periods of higher wholesale electricity prices, despite increased fuel costs (See Figure 13).

Spark spreads tend to be fairly volatile due to the volatility of both wholesale electricity and natural gas prices. Even at locations such as New York City, where natural gas infrastructure is relatively unconstrained, the spark spread will see volatility due to supply and demand fundamentals from competing fuel sources. As in 2021, spark spreads were occasionally negative in 2022 as fuel prices outstripped the cost of electricity, making running a natural gas-fired plant unprofitable during periods of low wholesale electricity prices and high natural gas prices. Importantly, although spark spreads are common metrics of profits for natural gas-fired plants, spark spreads do not consider the full costs of running a natural gas-fired plant, including pipeline costs such as fees and penalties.

Another way to express wholesale electricity prices is the all-in wholesale electricity price that includes additional costs to serve load, including capacity, transmission, and ancillary service costs. These additional costs can make significant contributions to the all-in wholesale electricity price. In 2021, capacity and transmission costs accounted for 36% of all-in wholesale electricity prices in PJM.<sup>14</sup> By contrast, ancillary services represent a small portion of the all-in wholesale electricity prices, making up just over 2% of all-in wholesale electricity prices in PJM.

All-in wholesale electricity prices in 2021, the most recent year with data available for all RTO/ISO markets, were elevated compared to historic levels. The elevated prices were largely due to increased energy costs, owing to both increased natural gas prices in 2021 and the February 2021 winter storm, which placed significant price pressure on many markets in 2021. SPP had a year-over-year increase of 116% from 2020 to 2021, while CAISO

14 PJM: Markets Report, PJM, April 25, 2022 <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220425/20220425-item-06a-market-operations-report.ashx>



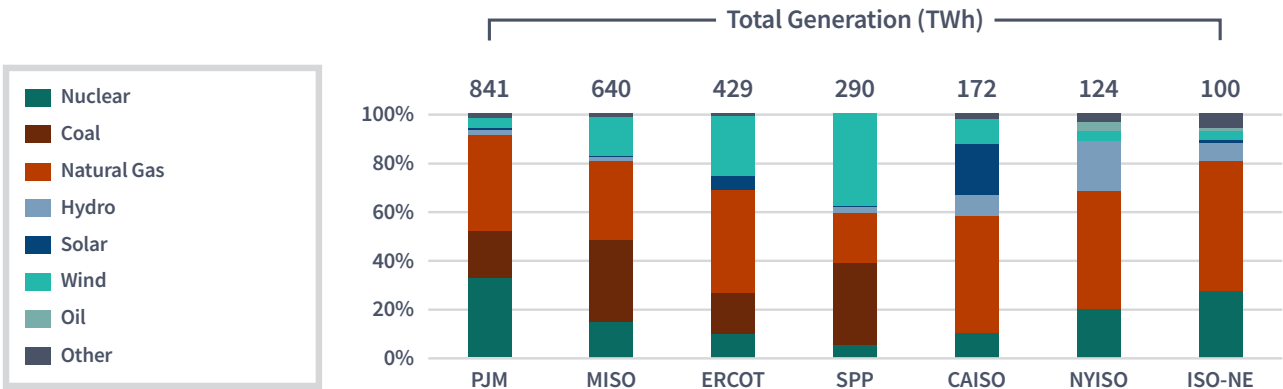
only had a 34% increase.<sup>15,16</sup> Neighboring markets had disparate outcomes as well, with NYISO having an 86% increase, while PJM had only a 48% increase.<sup>17, 18</sup>

All-in prices are reported differently across the RTOs/ISOs and, therefore, are not comparable. In particular, PJM and ISO-NE prices include both capacity and transmission costs in their all-in wholesale electricity price reporting, in addition to energy, ancillary services, and administrative costs. Reporting by CAISO, MISO, NYISO, and SPP of all-in wholesale electricity price includes only energy, ancillary services, and administrative costs.

**SUPPLY: ELECTRICITY GENERATION BY RESOURCE TYPE**

Electricity generation by resource type among all RTOs/ISOs continued recent trends, as net generation – defined as total generation minus auxiliary electricity consumption by the generating resource<sup>19</sup> – from wind increased from 13% to 14.4% and net generation from solar increased from 2.3% to 2.8% in the RTOs/ISOs between 2021 and 2022. Net generation from coal decreased from 24.4% to 21.3% over the same period.

**Figure 14: 2022 Total Electricity Generation and Percentage Share by Resource Type for RTOs/ISOs**



Source: EIA Form 930

Wind, coal, and natural gas experienced the biggest percentage changes in net generation among the RTOs/ISOs. For example, some of the biggest percentage changes in net generation occurred in SPP, where wind generation increased from 34.9% to 37.2%, overtaking coal as the largest generation source in SPP, as net generation from coal declined from 36.9% to 33.6% between 2021 and 2022. By contrast, wind generation declined in CAISO from 11.4% to 10%, while hydro generation increased from 7.1% to 8.6%. Net generation from coal in MISO declined from 38.8%

15 SPP: State of the Market 2021, May 23, 2022 <https://www.spp.org/documents/67104/2021%20annual%20state%20of%20the%20market%20report.pdf> at 127

16 CAISO: 2021 Annual Report on Market Issues & Performance, July 2022, <http://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf> at 106

17 NYISO: Operations and Markets Report, May 2022, [https://www.nyiso.com/documents/20142/30706539/Market%20Operations%20Report\\_%20BIC\\_05.19.22.pdf/401efa19-9df0-616e-782c-03083830c71e](https://www.nyiso.com/documents/20142/30706539/Market%20Operations%20Report_%20BIC_05.19.22.pdf/401efa19-9df0-616e-782c-03083830c71e) at A

18 PJM Market Report, January 24, 2022 <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220124/20220124-item-06a-markets-report.ashx> at 5

19 U.S. EIA, Glossary (Accessed January 7, 2023, <https://www.eia.gov/tools/glossary/index.php?id=N>).

to 33.9%, while natural gas generation increased from 29.4% to 32.6%. In NYISO, net generation from natural gas increased from 45% to 48.5%.

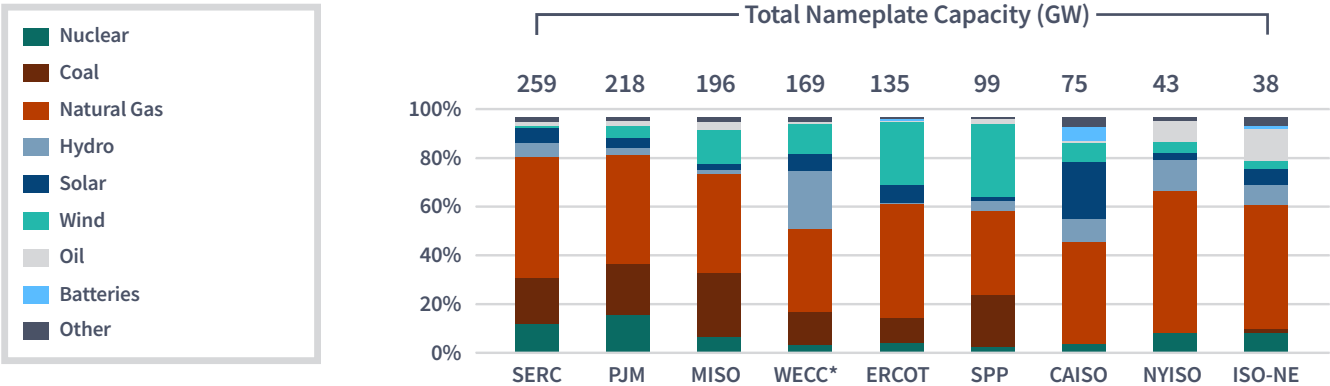
On a national level, as the price of natural gas delivered to U.S. electricity generation decreased in the last quarter of 2022, coal-fired generation became comparatively less economic, resulting in natural-gas fired generation displacing coal-fired generation and increasing the share of electricity generation from natural gas. With the increased share of electricity generation from natural gas, the share of electricity generation from coal decreased from 22.6% in 2021 to 20.2% in 2022.

Some utility customers are able to sell back energy onto the utility grid when, for instance, small-scale solar photovoltaic resources at a residence or business generate electricity levels that exceed the needs of that residence or business. U.S. residential and commercial customers sold a total of more than 3,228 gigawatt hour (GWh) of power to utilities in 2022, up from approximately 2,762 GWh in 2021. Nearly all the power sold to utilities occurred in the commercial and residential sectors in both years, with slight growth in 2022 totals over 2021 in each sector.

SUPPLY: RESOURCE ENTRY AND EXIT

Nationwide nameplate capacity additions and retirements in 2022 (measured in GW) followed the recent trends such that most capacity additions came from solar and wind resources and most retirements came from coal resources. Figure 15 provides a snapshot of the total nameplate capacity reflecting those additions and retirements as of the end of 2022. Figure 16 and Figure 18 highlight the resource mix shifts in different regional markets. The concept of resource availability, which differs from nameplate capacity, is highlighted in Figure 19 for solar and wind resources. The total nameplate capacity grew across the United States Aggregate nameplate capacity increased from 1,221 GW in 2021 to 1,233 GW. Figure 15 shows the total shares of electricity nameplate capacity, including the newly installed capacity, by resource type across both RTOs/ISOs and other regions in the United States as of December 2022. Natural gas represented 45% of the capacity mix across the United States, followed by coal at 17%, wind at 11%, and nuclear at 8%, nationwide.

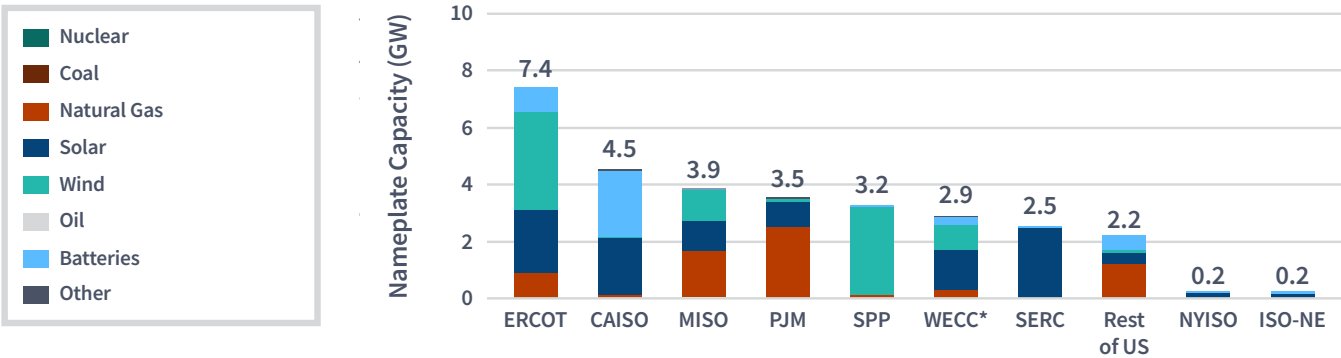
Figure 15: Total Nameplate Capacity and Percentage Share by Resource Type across the U.S.



NOTE: Data exclude Alaska and Hawaii. WECC\* refers to WECC without CAISO. Source: U.S. EIA Form-860M, January 2023 Release.

Some RTOs/ISOs experienced notable additions of certain resource types in their capacity mixes between 2021 and 2022. In CAISO, the share of battery storage capacity increased from 3.2% to 6.1%. In SPP, the percentage of wind capacity grew from 29.5% to 31.6%. In ERCOT, the proportion of solar capacity rose from 6.9% in 2021 to 8.2% in 2022. In NYISO, total coal capacity dropped to 0% in 2022 from 1.2% in 2021, after the retirement of the coal-fired Dunkirk Generation Plant.

**Figure 16: 2022 Nameplate Capacity Additions by Resource Type across the United States**

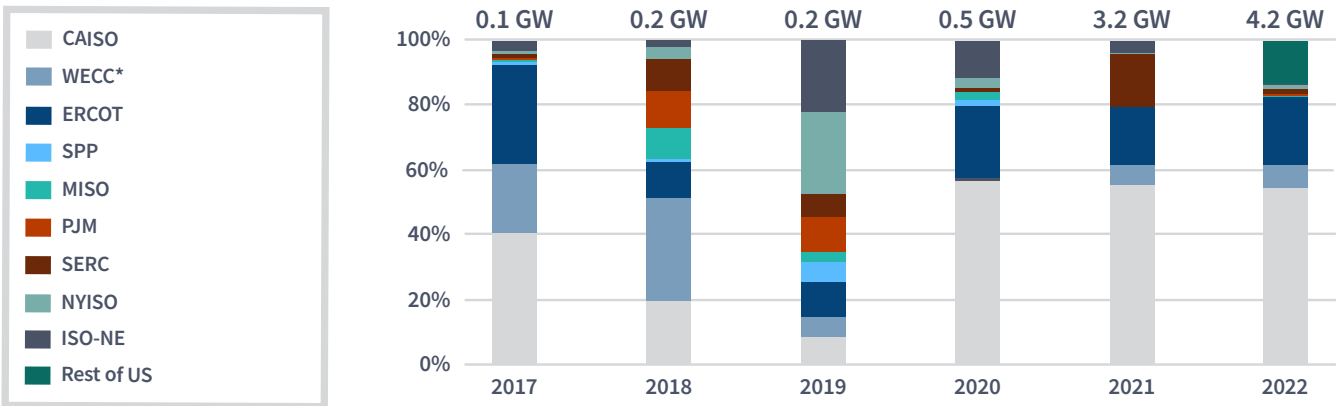


NOTE: Expected and actual additions and retirements from January 2022 through December 2022. Data exclude Alaska and Hawaii. WECC\* refers to WECC without CAISO. Source: U.S. EIA-Form 860M, January 2023 Release

With respect to capacity additions by resource type across the United States, most generation capacity additions in 2022 came from solar, wind, natural gas-fired, and battery storage resources. Among the RTO/ISOs, ERCOT added the most generating capacity with 7.4 GW of capacity additions in 2022. The largest resource additions in 2022 included the natural gas fired Jackson Generation combined-cycle natural gas plants in PJM (1,288 MW), the Traverse Wind Project in SPP (1,000 MW), and the Young Wind farm in ERCOT (500 MW).

Of note, battery storage additions represented over 3 GW of capacity for the second year in a row and were the fourth largest category. Battery storage additions nearly equaled natural gas capacity additions, which were the third largest category, behind wind and solar. Battery storage capacity additions increased from 3.2 GW in 2021 to 4.2 GW in 2022.

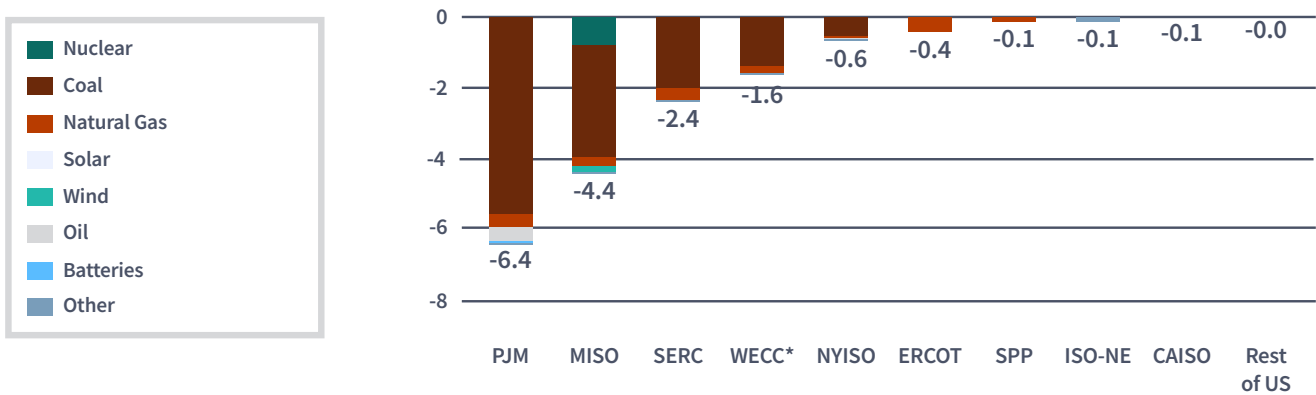
**Figure 17: 2022 Battery Storage Nameplate Capacity Additions across the United States**



Data exclude Alaska and Hawaii Source: U.S. EIA-Form 860M, January 2023 Release.

As Figure 17 shows, most of the battery storage additions occurred in CAISO, although most RTO/ISOs and non-RTO/ISO regions also added battery storage capacity. According to EIA estimates, the largest to the lowest battery storage additions by RTO/ISO are: CAISO (2.3 GW), ERCOT (890 MW), ISO-NE (55 MW), NYISO (34 MW), MISO (16 MW), and PJM (12 MW). SPP did not add battery storage capacity in 2022.

Figure 18: 2022 Nameplate Capacity Retirements by Resource Type across the United States



NOTE: Expected and Actual Additions and Retirements from January 2022 through December 2022. Data exclude Alaska and Hawaii. WECC\* refers to WECC without CAISO. Source: U.S. EIA Form -860M, January 2023 Release.

Figure 19: 2022 Expected Solar and Wind Resource Availability across Regions

NERC Assessment Areas	Solar (%)	NERC Assessment Areas	Solar (%)
ERCOT	81%	ERCOT	27%
SPP	80%	SPP	23%
California/Mexico	70%	California/Mexico	20%
PJM	64%	MISO	16%
MISO	50%	PJM	15%
New York	46%	New England	14%
New England	29%	New York	13%

Source: NERC 2022 Summer Reliability Assessment

Regarding capacity retirements by resource types across the United States, the largest share of capacity retirements across the country came from coal. In 2022, the 12.6 GW of coal-fired capacity retirements almost doubled 2021’s coal-fired capacity retirements. Notably, in 2021, coal retirements had declined relative to 2020 because of increased electricity demand and higher natural gas prices. Among the RTOs/ISOs, PJM retired the most capacity, with 6.4 GW of capacity retirements in 2022. Notable retirements included the coal-fired Dynegy W.H. Zimmer plant in PJM (1,425 MW) and the Entergy Palisades nuclear facility in MISO (812 MW).

As renewable resources continue to become a larger share of the generation mix, the load carrying capability of these resources during peak hours is expected to

vary across the United States. For example, in analyzing their contributions to the grid, NERC in its 2022 Summer Reliability Assessments reported solar and wind resources’ expected abilities to serve load during on-peak hours.<sup>20</sup> NERC calculated available capacity that is lower than nameplate capacity since the electricity output of solar and wind resources depends on weather conditions. NERC’s assessments took into account operating limitations such as fuel availability, transmission limitations, and environmental limitations to calculate available capacity. Figure

20 NERC, 2022 Summer Reliability Assessment at 45 (May 2022), [https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC\\_SRA\\_2022.pdf](https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf).

19 provides a more specific breakdown of the actual available percentages of solar and wind resources by NERC assessment areas, which can be referenced to the generation capacity entries of solar and wind in Figure 16.

## SUPPLY: CAPACITY MARKETS

Capacity markets provide a means to competitively procure resources to meet forecasted electricity demand, plus a planning reserve margin. Capacity markets are designed to provide economic signals encouraging efficient resource entry and exit. In 2022, the ISO-NE, NYISO, and PJM capacity markets cleared amounts in excess of the established capacity requirements. The MISO South sub-region was able to satisfy its capacity requirements, but the Midwest sub-region failed to do so. SPP and CAISO do not have formal capacity markets but have similar resource adequacy requirements. Resources in these regions are typically procured through bilateral or non-market means.<sup>21</sup>

For the four RTOs/ISOs that have capacity markets – ISO-NE, NYISO, PJM, and MISO – each capacity market is described below, including how capacity costs are reflected in wholesale power costs. ISO-NE, NYISO, and PJM capacity costs make up between 11% and 20% of the total all-in wholesale electricity cost in each of those RTOs/ISOs. ISO-NE capacity costs made up 20% of all-in wholesale electricity costs (transmission costs included) in 2021;<sup>22</sup> ISO-NE capacity costs made up 11% of all-in wholesale electricity costs (transmission costs included) from June through September of 2022.<sup>23</sup> In NYISO, capacity costs during the summer of 2021 were approximately 13% of all-in wholesale electricity costs (transmission costs excluded) for Long Island, with a lower percentage for the rest of the state.<sup>24</sup> Capacity costs during the summer of 2021 were nearly 8% of all-in wholesale electricity costs (transmission costs excluded) for New York City. PJM’s Market Monitor estimated that capacity payments made up 8.5% of all-in wholesale electricity costs (transmission costs included) between January and September of 2022.<sup>25</sup>

ISO-NE’s Forward Capacity Auction (FCA), held in February 2022, for the 2025-2026 capacity commitment period (FCA-16)<sup>26</sup>, resulted in an auction closing price of \$2.59 per kilowatt-month (kW-month) for the Rest-of-Pool zone.<sup>27</sup> The price is a 0.8% decrease from the February 2021 auction. With the 0.8% decrease from the 2021 auction price, the 2022 auction produced the second-lowest price result in ISO-NE’s forward capacity auctions. Amid lower clearing prices in FCA-16, total capacity payments are projected to be \$1.0 billion, down \$0.3 billion or 21% from the 2024-2025 capacity commitment period.<sup>28</sup> The lower clearing prices are due to a decline in the total capacity

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21 National Governors Association, *Electricity Markets – 101* (Accessed February 10, 2023), <https://www.nga.org/electricity-markets/>.

22 ISO New England Inc. Internal Market Monitor, *2021 Annual Markets Report*, Figure 2-1 at 36 (May 26, 2022), <https://www.iso-ne.com/static-assets/documents/2022/05/2021-annual-markets-report.pdf>.

23 ISO New England Inc. Internal Market Monitor, *Summer 2022 Quarterly Markets Report*, Figure 2-2 at 5 (November 2, 2022), <https://www.iso-ne.com/static-assets/documents/2022/11/2022-summer-quarterly-markets-report.pdf>.

24 Potomac Economics, *Quarterly Report on the NYISO Electricity Markets, Third Quarter 2022* at 25 (November 21, 2022), [https://www.potomaceconomics.com/wp-content/uploads/2022/12/NYISO-Quarterly-Report\\_2022Q3\\_11-21-2022.pdf](https://www.potomaceconomics.com/wp-content/uploads/2022/12/NYISO-Quarterly-Report_2022Q3_11-21-2022.pdf).

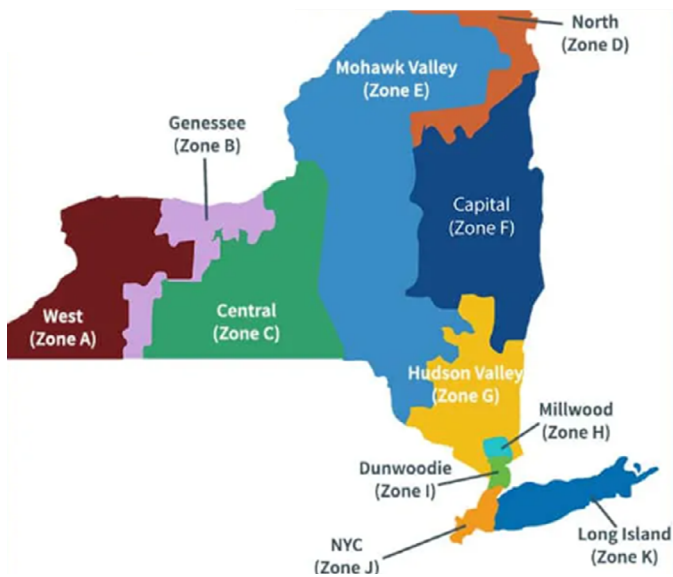
25 Monitoring Analytics, LLC, *2022 Quarterly State of the Market Report for PJM: January through September, Section 1 Introduction* at 18 (November 11, 2022), [https://www.monitoringanalytics.com/reports/PJM\\_State\\_of\\_the\\_Market/2022/2022q3-som-pjm-sec1.pdf](https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022q3-som-pjm-sec1.pdf).

26 This is the second consecutive year that ISO-NE has divided the region into four zones that reflect local capacity requirements and power system transmission constraints. The four zones include: Southeast New England (SENE), Northern New England (NNE), Nested Maine, and Rest-of-Pool. ISO-NE, *New England’s Forward Capacity Auction Closes with Adequate Power System Resources for 2025-2026* (March 21, 2022), <https://isonewire.com/2022/03/09/new-englands-forward-capacity-auction-closes-with-adequate-power-system-resources-for-2025-2026/>.

27 ISO-NE, *Results of the Annual Forward Capacity Auctions* (Accessed January 11, 2022), <https://www.iso-ne.com/about/key-stats/markets#fcaresults>.

28 ISO-NE, *2021 Annual Markets Report* at 25 (May 26, 2022), <https://www.iso-ne.com/static-assets/documents/2022/05/2021-annual-markets-report.pdf>.

**Figure 20: New York Capacity Zones, A-K.**



Source: NERC 2022 Summer Reliability Assessment

supply obligation and less price separation in the import-constrained Southeastern New England capacity zone. Total capacity resources cleared were 32,810 MW, representing a decrease of 1,811 MW from 2021's results<sup>29</sup> and 1,165 MW<sup>30</sup> above the installed capacity requirement. Cleared capacity resources for FCA-16 consisted of 27,984 MW of generation within the ISO-NE footprint, 3,323 MW of demand response, and 1,504 MW of imports.<sup>31</sup>

NYISO cleared capacity averaged 37,868 MW for monthly spot auctions in 2022 (813 MW of demand response) – a 588 MW decrease from 2021.<sup>32</sup> Unlike ISO-NE and PJM, NYISO does not have a three-year forward auction, and instead has seasonal summer and winter strip auctions, which supplement monthly spot auctions. Weighted average summer capacity prices for Rest of State<sup>33</sup> in NYISO dropped 39% from 2021 levels to \$3.12/kW-month.<sup>34</sup> Although 2022 Long Island weighted average

capacity prices were the highest in NYISO at \$4.36/kW-month, this was a decline of nearly 17% from the weighted average price in 2021. The sharp decline in weighted average annual Long Island prices resulted from weighted average summer capacity prices declining from \$9.55/kW-month in 2021, to \$6.50/kW-month in 2022. The Locational Minimum Installed Capacity Requirement—the portion of installed capacity that must be physically located within a locality to meet reliability standards—for Long Island was lower than in 2021 resulting in lower weighted average summer capacity regions.<sup>35</sup>

However, a higher load forecast and retirement of generation in Long Island kept prices higher. For comparison, in New York City in 2022, the weighted average annual capacity prices were \$2.79/kW-month, and the weighted average summer capacity prices were \$3.61/kW-month. Capacity prices in New York City were comparable to the capacity prices for Rest of

29 ISO-NE, *Results of the Annual Forward Capacity Auctions* (Accessed January 11, 2022), <https://www.iso-ne.com/about/key-stats/markets#fcaresults>.

30 ISO-NE, *Operating Reserve Deficiency Information – Capacity Commitment Period 2025-2026 Memo*, Figure 1 at 4 (December 7, 2021), [https://www.iso-ne.com/static-assets/documents/2021/12/a00\\_pspc\\_2021\\_12\\_iso\\_memo\\_or\\_def\\_fca\\_16.pdf](https://www.iso-ne.com/static-assets/documents/2021/12/a00_pspc_2021_12_iso_memo_or_def_fca_16.pdf).

31 ISO-NE, *New England's Forward Capacity Auction Closes with Adequate Power System Resources for 2025-2026* (March 21, 2022), <https://isone.wire.com/2022/03/09/new-englands-forward-capacity-auction-closes-with-adequate-power-system-resources-for-2025-2026/>.

32 NYISO, *Installed Capacity Data, Monthly UCAP Reports, ICAP Market Report – December 2022, Summary Table* (November 30, 2022), <https://www.nyiso.com/installed-capacity-market>.

33 Rest of State refers to zones A-F. Potomac Economics, *2021 State of the Market Report for the New York ISO Markets* at iii (May 2022), <https://www.nyiso.com/documents/20142/2223763/NYISO-2021-SOM-Full-Report-5-11-2022-final.pdf>.

34 NYISO, *Installed Capacity Data, Monthly UCAP Reports, ICAP Market Report – December 2022, Summary Table* (November 30, 2022), <https://www.nyiso.com/installed-capacity-market>.

35 NYISO, *Locational Minimum Installed Capacity Requirements Study* at 2 (January 13, 2022), <https://www.nyiso.com/documents/20142/27428389/LCR2022-Report.pdf>; NYISO, *Locational Minimum Installed Capacity Requirements Study* at 2 (January 14, 2021), <https://www.nyiso.com/documents/20142/17462310/LCR2021-Report.pdf>.

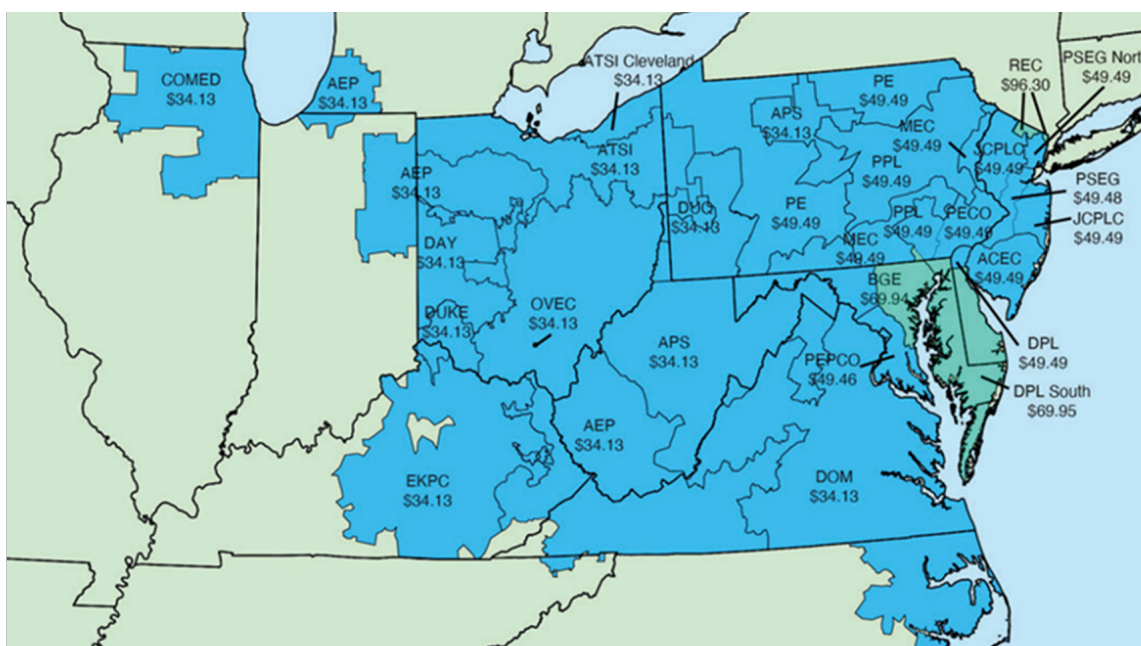


State as conditions were relatively tighter systemwide than they were in the nested localities like New York City.<sup>36</sup>

Similar to the Long Island and Rest of State zones, prices in the G-J Locality—representing the Lower Hudson Valley—also decreased. G-J Locality weighted average annual capacity prices decreased by 13% to \$2.67/kW-month and weighted average summer capacity prices decreased by nearly 34% to \$3.36/kW-month. In 2021 and 2022 capacity prices for the G-J Locality were set by the statewide curve throughout the year, meaning price decreases in 2022 were caused by changes in Rest of State. The lower prices were partly driven by lower peak load forecasts.<sup>37</sup>

The PJM capacity market auction held in June 2022, for the 2023-2024 capacity commitment period<sup>38</sup>, resulted in an auction clearing price of \$34.13/MW-day (\$1.02/kW-month) for most of the RTO (blue area denoted in Figure 21).<sup>39</sup> The MAAC, DPL-SOUTH and BGE<sup>40</sup> delivery areas cleared at higher prices (shown in green in Figure 21).<sup>41</sup> The \$34.13/MW-day (\$1.02/kW-month) clearing price was \$15.87/MW-day (\$0.48/kW-month) lower than the \$50/MW-day (\$1.5/

**Figure 21: 2023/24 PJM Base Residual Auction Results**



Source: 2022 Quarterly State of the Market Report for PJM, January through June

36 From a capacity perspective, in 2022, conditions were relatively tighter systemwide than they were in the nested localities like New York City. Therefore, the systemwide price was setting the price (or nearly setting the price) for those nested localities. For example, a New York City resource will sell capacity at the Rest of State price (i.e., systemwide price) if the Rest of State price is greater than the New York City price. Potomac Economics, *Quarterly Report on the New York ISO Electricity Markets, Third Quarter of 2022* at 21 (November 2022), [https://www.potomaceconomics.com/wp-content/uploads/2022/12/NYISO-Quarterly-Report\\_2022Q3\\_11-21-2022.pdf](https://www.potomaceconomics.com/wp-content/uploads/2022/12/NYISO-Quarterly-Report_2022Q3_11-21-2022.pdf).

37 *Id.*

38 PJM, *2023/2024 RPM Base Residual Auction Results* (June 21, 2022), <https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2023-2024/2023-2024-base-residual-auction-report.ashx>.

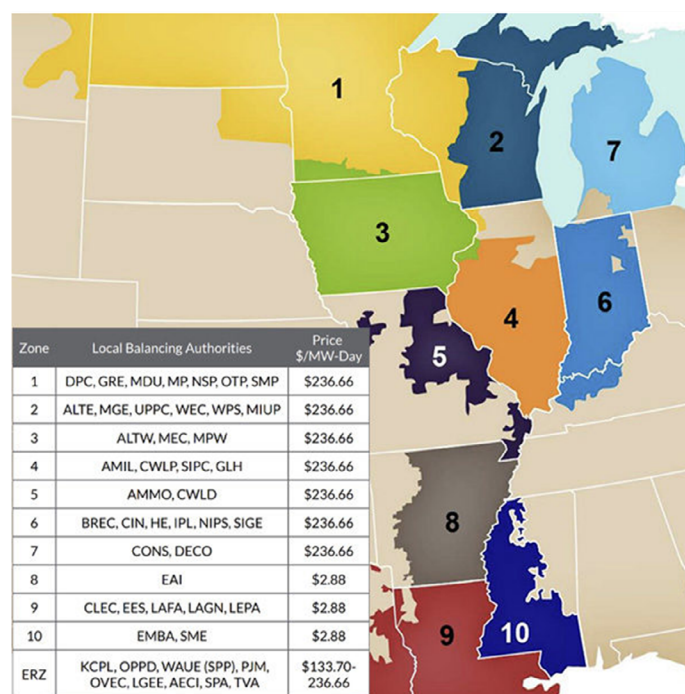
39 PJM and MISO measure capacity prices in \$ per Megawatt-day (\$/MW-day). ISO-NE and NYISO measure capacity prices in \$ per kilowatt-month (\$/kW-month). \$1 per kW-month equals approximately \$33 per MW-day.

40 The MAAC zones, located in Pennsylvania, New Jersey, and the Delmarva peninsula, are depicted in light blue. BGE and DPL South are depicted in light green.

41 Monitoring Analytics, LLC, *2022 Quarterly State of the Market Report for PJM, January through June* at 342 (August 11, 2022), [https://www.monitoringanalytics.com/reports/PJM\\_State\\_of\\_the\\_Market/2022/2022q2-som-pjm.pdf](https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022q2-som-pjm.pdf).

kW-month) clearing price for the delivery year beginning June 1, 2023 and ending May 31, 2024.<sup>42</sup> The lower capacity prices for the 2023/2024 commitment period will reduce total capacity revenues in PJM by \$1.8 billion, or over 40%.<sup>43</sup> The clearing price results were among the lowest since the auction held for the delivery year beginning June 1, 2013. The auction cleared 144,871 MW of unforced capacity. The auction procured capacity equivalent to a 20.3% reserve margin, 5.5% higher than the required reserve margin of 14.8%. Cleared capacity included 3,330 MW of new generation, 405 MW of generation uprates, 1,397 MW of imports, 8,096 MW of demand response, and 5,471 MW of energy efficiency. The PJM capacity auction for the 2024/2025 commitment period opened on December 7, 2022. On February 21, 2023, the Commission issued an order approving PJM's December proposal to adjust its capacity market rules and to apply those revisions to the 2024/2025 BRA.<sup>44</sup> PJM posted the results on February 27, 2023.<sup>45</sup>

**Figure 22: 2022/2023 MISO Auction Results**



Source: MISO

Historically, MISO's annual Planning Resource Auction has cleared at prices much lower than the other RTO/ISO capacity markets. In the Planning Resource Auction held April 2022 for the 2022/2023 planning year, 100,515 MW were offered compared to 93,807 MW for the 2021/2022 planning year.<sup>46</sup> Cleared capacity and fixed resource adequacy plans were slightly higher than the prior year by nearly 200 MW, which included over 7,500 MW<sup>47</sup> of demand response. However, planning reserve margin requirements increased over 1,400 MW. Most notably, four of the Midwest zones failed to satisfy their capacity requirements and triggered the cost of new entry<sup>48</sup> pricing across all seven Midwest zones. Despite importing over 3,000 MW from external sources and from the South zones, MISO's Midwest zones still experienced a shortfall against the requirement.<sup>49</sup> In the Midwest zones, auction clearing prices were \$236.66/MW-day (\$7.10/kW-month), which rose by over 3,000%, a drastic change compared to recent years. In the South zones (the Entergy footprint), auction clearing prices were \$2.88/MW-day (\$0.09/kW-month).<sup>50</sup> The MISO market

42 PJM and MISO measure capacity prices in \$ per Megawatt-day (\$/MW-day). ISO-NE and NYISO measure capacity prices in \$ per kilowatt-month (\$/kW-month). \$1 per kW-month equals approximately \$33 per MW-day.

43 PJM, News Release, PJM Capacity Auction Secures Electricity Supplies at Competitive Prices (June 21, 2022), <https://www.pjm.com/-/media/about-pjm/newsroom/2022-releases/20220621-pjm-capacity-auction-secures-electricity-supplies-at-competitive-prices.ashx>.

44 PJM Interconnection, L.L.C., 182 FERC 61,109 (2023).

45 PJM, News Release, PJM Capacity Auction Procures Adequate Resources (February 27, 2023), <https://insidelines.pjm.com/pjm-capacity-auction-procures-adequate-resources/>.

46 S&P Global Market Intelligence, Commodity Charting, ISO Capacity Summary, *MISO Capacity Markets* (2022).

47 MISO, 2022/2023 Planning Resource Auction (PRA) Results at 14 (April 14, 2022), <https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf>.

48 Cost of new entry is used to indicate the current annualized, capital cost of constructing a power plant. MISO uses the cost of new entry as the maximum offer and maximum clearing price, converted to a daily value, in the Planning Resource Auctions. MISO, Cost of New Entry PY 2022/2023 at 4 (October 2021), <https://cdn.misoenergy.org/20211006%20RASC%20Supplemental%20Materials%20CONE%202021-2022595294.pdf>.

49 MISO, 2022/2023 Planning Resource Auction (PRA) Results at 5 (April 14, 2022), <https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf>.

50 S&P Global Market Intelligence, Commodity Charting, ISO Capacity Summary, *MISO Capacity Markets* (2022).

monitor stated the Midwest zones failed to satisfy their requirements given the load forecast increased over the prior year, and the retirement of multiple conventional resources.<sup>51</sup> Although installed nameplate capacity has increased in the last five years in MISO from approximately 190 GW to 196 GW, accredited capacity<sup>52</sup> has decreased with the growth of renewable generation capacity, as discussed above in resource entry and exit.

## Capacity Imports

PJM, ISO-NE, NYISO, and MISO allow external resources that meet each RTO/ISO's requirements to participate in their capacity markets, providing capacity to the RTO/ISO while being physically located outside its footprint. External resources increase supply in constrained markets and provide additional reliability benefits, while moderating capacity prices through increased competition.

In the PJM capacity auction conducted in June 2022 for the 2023/2024 delivery year, 1,397 MW of external capacity cleared the auction out of a total cleared capacity of 144,871 MW, just under 1% of total cleared capacity.<sup>53</sup> External capacity was down approximately 10% compared to the prior auction when 1,558 MW of external capacity cleared. External resources located in the MISO footprint provided 60% of external capacity in PJM's auction for 2023/2024 delivery year, similar to other recent years.<sup>54</sup> Relative to PJM's 1% of total capacity coming from external resources MISO had 3,639 MW of capacity clear in the 2022-23 auction from external resources, out of a total of 134,095 MW of cleared capacity (2.7%). This was slightly lower than the 3,798 MW that cleared in the 2021-22 auction and the 3,736 MW that cleared in 2020-21.<sup>55</sup>

In the latest FCA-16 auction, ISO-NE qualified 3,565 MW of which 1,504 MW received a capacity obligation, out of a total of 32,810 MW (4.6%).<sup>56</sup> In 2021, ISO-NE qualified 3,632 MW of external resources to bid in the FCA-15 auction, with 1,487 MW of those resources clearing.<sup>57</sup>

Capacity imports also have a limited role in the NYISO capacity market. In 2022, net capacity purchases with neighboring control areas averaged 1,307 MW for the year, or 3.5% of cleared capacity.

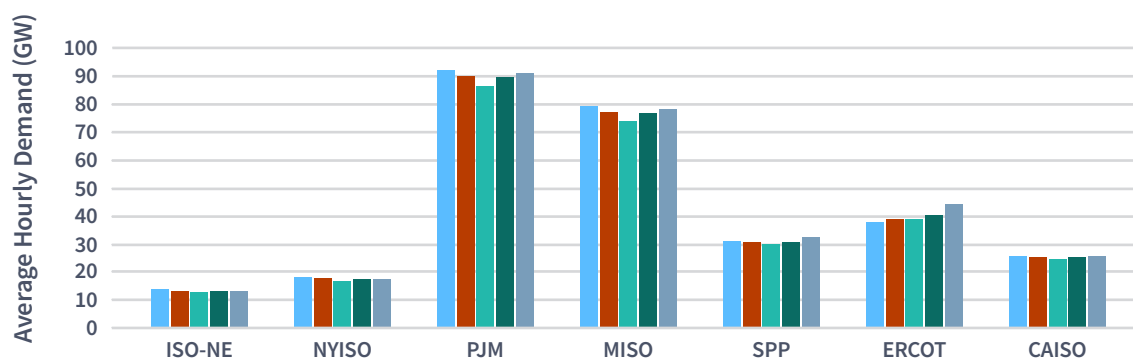
- 
- 51 Potomac Economics, *IMM Quarterly Reports, Spring 2022* at 7 (July 14, 2022), [https://www.potomaceconomics.com/wp-content/uploads/2022/06/IMM-Quarterly-Report\\_Spring-2022-MSC.pdf](https://www.potomaceconomics.com/wp-content/uploads/2022/06/IMM-Quarterly-Report_Spring-2022-MSC.pdf).
- 52 As MISO has studied high levels of renewable penetration on the grid within its Renewable Integration Impact Assessment (RIIA) study, it has recognized that its capacity accreditation framework – the manner by which it assesses variable renewables' ability to contribute to peak demand needs – will likely change as these resources become more prevalent on the grid. MISO's current resource adequacy requirements do not consider the expected marginal decline in load carrying capability from renewables as penetration increases. MISO Dashboard, *Forward Capacity Accreditation for Renewable Resources (fka IR095) RASC-2020-4* (December 12, 2022), <https://www.misoenergy.org/stakeholder-engagement/MISO-Dashboard/forward-capacity-accreditation-for-renewable-resources/>; MISO, *2022/2023 Planning Resource Auction (PRA) Results* at 7 (April 14, 2022), <https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf>.
- 53 PJM, *2023/2024 RPM Base Residual Auction Results* at 1 (2022), <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2023-2024/2023-2024-base-residual-auction-report.ashx>.
- 54 Monitoring Analytics, *Analysis of the 2023/2024 RPM Base Residual Auction* at 106 (October 28, 2022), [https://www.monitoringanalytics.com/reports/Reports/2022/IMM\\_Analysis\\_of\\_the\\_20232024\\_RPM\\_Base\\_Residual\\_Auction\\_20221028.pdf](https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf).
- 55 MISO, *2022/2023 Planning Resource Auction Results* at 14 (2022), <https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf>.
- 56 ISO-NE Internal Market Monitor, *2020 Annual Markets Report* at 195 (May 2022), <https://www.iso-ne.com/static-assets/documents/2022/05/2021-annual-markets-report.pdf>.
- 57 ISO-NE Internal Market Monitor, *2020 Annual Markets Report* at 192 (June 2021), <https://www.iso-ne.com/static-assets/documents/2021/06/2020-annual-markets-report.pdf>.

## ELECTRICITY DEMAND

Electricity demand increased in each RTO/ISO in 2022, as the economy continued to recover from the impact of the COVID-19 pandemic. The highest increase relative to 2021 was in ERCOT, which saw an average hourly demand increase of 10.21%, followed by SPP, which rose by 5.61%. By comparison, demand in ISO-NE was only 0.13% higher in 2022. Weather had a notable influence on electricity demand in 2022 at times, as the December 2022 winter storm drove up electricity demand in the fourth quarter with significant increases in ERCOT, SPP, MISO, and PJM. The warmer than average summer likewise drove up electricity demand in most markets comparable to 2021. Most markets generally demonstrated heating and cooling demands similar to those of 2021. With these weather effects considered, most markets continued to be near their five-year averages, as shown in Figure 23.

Electricity demand growth in 2022 follows a long-term trend of limited-to-negative electricity demand growth due to more efficient energy use. Some grid operators, in addition to the RTOs/ISOs, have begun to investigate how the electrification of the transportation and heating sectors and the growth of data centers will change future electricity demand.<sup>58</sup>

**Figure 23: Average Hourly Demand by RTO/ISO**



2018 2019 2020 2021 2022

Source: Hitachi ABB Power Grids Velocity Suite Based on RTO/ISO Total Load Dataset

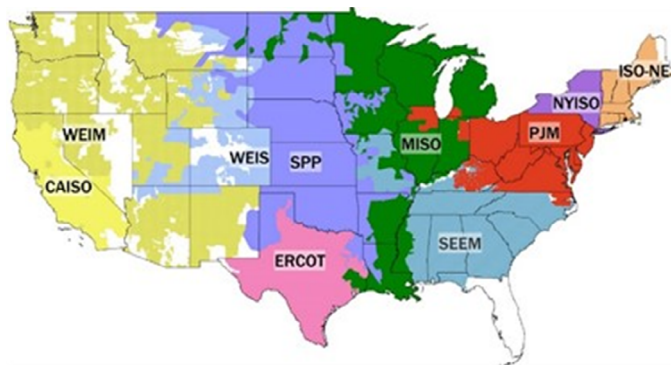
## ELECTRICITY MARKET EXPANSION AND NEW ARRANGEMENTS

Expansion of wholesale electricity market arrangements continued in 2022. The Southeast Energy Exchange Market (SEEM), a platform to facilitate bilateral trades, was launched in the southeast, and more participants joined the Western Energy Imbalance Market (WEIM) and the Western Energy Imbalance Service (WEIS), both of which are real-time market arrangements that generate cost savings by optimizing the electricity imbalance amongst participating entities using a least-cost, security constrained dispatch.

58 ISO-NE, *Electrification of Transportation in New England – Looking Ahead* (Oct. 2022), [https://www.iso-ne.com/static-assets/documents/2022/10/isone\\_uri\\_10\\_20\\_2022.pdf](https://www.iso-ne.com/static-assets/documents/2022/10/isone_uri_10_20_2022.pdf); NYISO, *Power Trends 2022: The Path to a Reliable, Greener Grid for New York* (Jun. 2022), <https://www.nyiso.com/documents/20142/2223020/2022-Power-Trends-Report.pdf>; PJM, *2023 Long-Term Load Forecast Predicts Growth Fueled by Data Centers* (Jan. 2023), <https://insidelines.pjm.com/2023-long-term-load-forecast-predicts-growth-fueled-by-data-centers/>; MISO, *MISO Electrification Insights* (Apr. 2021), <https://cdn.misoenergy.org/Electrification%20Insights538860.pdf>; CAISO, *20-Year Transmission Outlook* (March 2022), <http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf>.



**Figure 24: Organized U.S. Wholesale Electricity Market Arrangements in 2022**



Source: Hitachi ABB Power Grids Velocity Suite

SEEM is a new bilateral trading platform that facilitates the trade of wholesale electricity every 15-minutes in the southeast. SEEM matches buyers and sellers of electricity using available transmission capacity and establishes a mutually agreeable price for each trade. At launch in November 2022, SEEM members serve 11 states with more than 160,000 MW of summer capacity, creating a trading platform. The generation mix in the SEEM footprint is weighted toward gas-fired (40%) and coal-fired (28%) generation facilities, with nuclear, wind, and other fuels rounding out the remainder. According to SEEM, during the last two months of 2022, SEEM facilitated over 60 GWh of trade.<sup>59</sup>

Western energy imbalance markets expanded in 2022. In particular, four balancing authority areas (Bonneville

Power Administration, Tucson Electric Power, Avista, and Tacoma Power) entered the WEIM, increasing the total number to 19 participants, serving 77% of the demand for electricity in the Western United States.<sup>60</sup> In 2022, according to CAISO, WEIM provided economic benefits<sup>61</sup> over \$500 million from July to September through cost savings, as strong hydro conditions and high natural gas prices coincided with strong energy demand from extreme heat across the west.<sup>62</sup> CAISO identified the enhanced coordination with other regional utilities and members of the WEIM as a key factor supporting reliability during a ten-day stretch of triple-digit heat in early September.<sup>63</sup> One balancing authority area (Colorado Springs Utilities) joined SPP's WEIS, increasing the total number to 7 participants with approximately 5 GW of electricity demand during its second year of operations.

## Other Market Developments

Heightened geopolitical risk drove up forward-looking risk expectations in the U.S. natural gas market year-over-year in 2022. In addition, other fuels such as jet fuel and propane saw prices rise significantly in 2022, as crude oil prices increased from 2021 to 2022.

## CREDIT TRENDS AND EVENTS IN THE MARKETS

This section discusses major credit trends and credit-stress events in organized electricity markets and fuel markets occurring in 2022.

59 Southeast Energy Exchange Market, *Public Data*, <https://southeastenergymarket.com/reports/>

60 CAISO, California ISO welcomes BPA and Tucson Electric Power to the WEIM (May 2022), <https://www.westerneim.com/Documents/California-ISO-Welcomes-BPA-and-Tucson-Electric-Power-to-the-WEIM.pdf>.

61 WEIM calculates the total WEIM benefit as the cost savings of the WEIM dispatch compared with a counterfactual without the WEIM dispatch. See CAISO, *EIM Quarterly Benefit Report Methodology*, <https://www.westerneim.com/Documents/EIM-BenefitMethodology.pdf>.

62 CAISO, WEIM posts \$526 million in quarterly benefits (October 2022), <https://www.westerneim.com/Documents/weim-posts-526-million-in-quarterly-benefits.pdf>.

63 CAISO, *California ISO posts analysis of September heat wave* (November 2022), <https://www.westerneim.com/Documents/california-iso-posts-analysis-of-september-heat-wave.pdf>.

According to S&P Global,<sup>64</sup> macroeconomic conditions and supply/demand fundamentals supported credit quality in the oil and gas sector in 2022. While demand-related concerns about recessions and persistent lockdowns in China due to COVID-19 put downward pressure on global crude oil prices in 2022, these prices were also supported by many factors, largely on the supply side. In 2022, crude oil production by OPEC+, an alliance of oil-producing countries led by Saudi Arabia and including Russia, remained below pre-pandemic levels with several members pumping significantly below their quotas.<sup>65</sup> In North America, crude oil production growth in 2022 was limited in part as producers continued to limit capital spending and use cash flow to pay down debt and augment returns to investors.<sup>66</sup> Limited capital spending on oil and gas exploration and production in recent years has contributed to limited production growth.<sup>67</sup> Besides the contribution of limited growth in crude oil output to support global crude oil prices, a significant geopolitical risk premium was embedded in global crude oil prices in 2022 due to the Russia-Ukraine conflict. The geopolitical fallout of this conflict in turn further upset natural gas markets worldwide. In the United States, implied volatility of the New York Mercantile Exchange (NYMEX) futures options contracts for the Henry Hub in Louisiana, a measure of forward-looking risk expectations in the U.S. natural gas market, increased year-over-year in 2022 as a series of events upset the international LNG markets following the Russian invasion of Ukraine in February and including the cut-off of natural gas supplies from Russia to Europe initiated in August 2022.<sup>68</sup>

## JET FUEL MARKETS

The Interstate Commerce Act provides the Commission jurisdiction over interstate pipelines transporting oil products, including jet fuel and propane.<sup>69</sup> In 2020, the COVID-19 pandemic induced significant declines in jet fuel demand before slowly recovering in 2021. In 2022, jet fuel demand increased further, averaging 1.56 million barrels per day (bbl/day) for the year, 14% or 0.19 million bbl/day above 2021 demand levels.<sup>70</sup> Jet fuel inventory levels started 2022 at low levels as jet fuel inventories fell to 34.96 million bbl by the end of December 2021, the lowest level since August 2014, due to increased demand and decreased production.<sup>71</sup> Jet fuel inventories struggled to recover in 2022, reaching a peak of 41.63 million bbl in the last week of July. Jet fuel inventories ended 2022 at around 34 million bbl, the lowest jet fuel inventories level since spring 1996.<sup>72</sup>

U.S. refinery net production of jet fuel in 2022 averaged 1.60 million bbl, 24% above 2021 production but only 4%

64 S&P Global, *S&P Global Ratings Revises Its Oil and Gas Price Assumptions on Supply/Demand Fundamentals* (November 18, 2022), <https://www.spglobal.com/ratings/en/research/articles/221118-s-p-global-ratings-revises-its-oil-and-gas-price-assumptions-on-supply-demand-fundamentals-12567952>.

65 S&P Global, *OPEC+ crude oil production rises in September, but still widely lags quotas: Platts survey – S&P Global* (October 10, 2022), <https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/oil/101022-opec-crude-oil-production-rises-in-september-but-still-widely-lags-quotas-platts-survey>.

66 U.S. EIA, *This Week in Petroleum*, December 14, 2022, [https://www.eia.gov/petroleum/weekly/archive/2022/221214/includes/analysis\\_print.php](https://www.eia.gov/petroleum/weekly/archive/2022/221214/includes/analysis_print.php)

67 S&P Global, *Even as oil and gas capex rises, free cash flow continues to increase*, (February 7, 2023), <https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/even-as-oil-and-gas-capex-rises-free-cash-flow-continues-to-increase-74128969>.

68 Reuters, *Russia deepens Europe's energy squeeze with new gas halt* (August 30, 2022), <https://www.reuters.com/business/energy/new-russia-gas-halt-tighten-energy-screws-europe-2022-08-30/>.

69 Interstate Commerce Act, 49 U.S.C. app. § 1(1), available at <https://www.ferc.gov/sites/default/files/2020-06/ica.pdf>.

70 U.S. EIA, *U.S. Product Supplied of Kerosene-Type Jet Fuel (Thousand Barrels per Day)*, Released February 28, 2023, <https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MKJUPUS2&f=M>.

71 U.S. EIA, *Less Production And More Demand Have Reduced U.S. Jet Fuel Inventories* (December 13, 2021), <https://www.eia.gov/todayinenergy/detail.php?id=50627>.

72 U.S. EIA, *Weekly U.S. Ending Stocks of Kerosene-Type Jet Fuel (Thousand Barrels)*, Released March 1, 2023, <https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=WKJSTUS1&f=W>.



above the five-year average.<sup>73</sup> As a result of low inventories, increasing demand, and flat production,<sup>74</sup> the spot price of jet fuel (U.S. Gulf Coast Kerosene-Type Jet Fuel Spot Price) in 2022 averaged \$3.37/gallon, 82% above 2021 average and more than double the five-year average.<sup>75</sup>

## PROPANE MARKETS

Below-average propane inventories and high exports led to increased propane prices during the first half of 2022 despite nearly flat domestic demand and increased production.<sup>76</sup>

In 2022, total propane production, which includes production from both natural gas processing plants as well as net production from refineries and petroleum storage terminal blending facilities,<sup>77</sup> increased 6% above 2021 levels and 18% above the five-year average.<sup>78</sup> However, strong exports and a slight increase in domestic demand contributed to weak propane inventories. Total propane exports in 2022 were 4% above 2021 levels at 503 million barrels, 24% above the previous five-year average.<sup>79</sup> Domestic propane demand in 2022 was 1% above 2021 levels at 307 million barrels, 0.3% below the five-year average.<sup>80</sup> Since 2017, the amount of annual propane exports has been growing and has consistently exceeded annual domestic propane demand.<sup>81</sup>

During the first nine months of 2022, propane inventories were below the five-year average, continuing the trend from 2021, before recovering to above the five-year average in October. During January-August, propane inventories remained, on average, 14% below the five-year average for the same months. In September 2022, propane inventories were 1% below September 2021 levels, and in October, propane inventories recovered to 4% above 2021 levels for that month.<sup>82</sup>

Weak propane inventories in the first half of 2022 combined with high demand resulted in high propane prices in the first half of 2022.<sup>83</sup> Average residential propane prices<sup>84</sup> for 2022 were \$2.76/gallon, 11% above the average price of \$2.49/gallon seen in 2021. Residential propane prices rose to \$3.02/gallon in mid-March, the highest residential

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73 U.S. EIA, *4-Week Avg U.S. Refiner Net Production of Kerosene-Type Jet Fuel (Thousand Barrels per Day)*, Released March 1, 2023, [https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=w\\_epjk\\_ypr\\_nus\\_mbbld&f=4](https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=w_epjk_ypr_nus_mbbld&f=4).

74 U.S. EIA, *Less U.S. Jet Fuel Consumption on Average in 2022 Than in 2019* (December 5, 2022) <https://www.eia.gov/todayinenergy/detail.php?id=54879&src=email>.

75 U.S. EIA, *U.S. Gulf Coast Kerosene-Type Jet Fuel Spot Price FOB (Dollars per Gallon)*, Released March 1, 2023, [https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=EER\\_EPJK\\_PF4\\_RGC\\_DPG&f=M](https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=EER_EPJK_PF4_RGC_DPG&f=M).

76 U.S. EIA, *Households Heated Primarily With Heating Oil or Propane Will Likely Pay More This Winter* (October 13, 2022), [https://www.eia.gov/petroleum/weekly/archive/2022/221013/includes/analysis\\_print.php](https://www.eia.gov/petroleum/weekly/archive/2022/221013/includes/analysis_print.php).

77 The EIA defines refinery and blender net production as "...liquefied refinery gases, and finished petroleum products produced at a refinery or petroleum storage terminal blending facility. Net production equals gross production minus gross inputs." EIA, Glossary, <https://www.eia.gov/tools/glossary/>.

78 U.S. EIA, *Propane Supply and Disposition*, Released February 28, 2023, [http://www.eia.gov/dnav/pet/pet\\_sum\\_snd\\_a\\_epllpa\\_mbbld\\_m\\_cur.htm](http://www.eia.gov/dnav/pet/pet_sum_snd_a_epllpa_mbbld_m_cur.htm).

79 U.S. EIA, *Propane Supply and Disposition*, Released February 28, 2023, [http://www.eia.gov/dnav/pet/pet\\_sum\\_snd\\_a\\_epllpa\\_mbbld\\_m\\_cur.htm](http://www.eia.gov/dnav/pet/pet_sum_snd_a_epllpa_mbbld_m_cur.htm).

80 U.S. EIA, *Propane Supply and Disposition*, Released February 28, 2023, [http://www.eia.gov/dnav/pet/pet\\_sum\\_snd\\_a\\_epllpa\\_mbbld\\_m\\_cur.htm](http://www.eia.gov/dnav/pet/pet_sum_snd_a_epllpa_mbbld_m_cur.htm).

81 U.S. EIA, *Propane Supply and Disposition*, Released February 28, 2023, [http://www.eia.gov/dnav/pet/pet\\_sum\\_snd\\_a\\_epllpa\\_mbbld\\_m\\_cur.htm](http://www.eia.gov/dnav/pet/pet_sum_snd_a_epllpa_mbbld_m_cur.htm).

82 U.S. EIA, *U.S. Ending Stocks of Propane*, Released February 28, 2023, [https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=M\\_EPLLPA\\_SAE\\_NUS\\_MBBLD&f=M](https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=M_EPLLPA_SAE_NUS_MBBLD&f=M).

83 U.S. EIA, *Households Heated Primarily With Heating Oil or Propane Will Likely Pay More This Winter* (October 13, 2022), [https://www.eia.gov/petroleum/weekly/archive/2022/221013/includes/analysis\\_print.php](https://www.eia.gov/petroleum/weekly/archive/2022/221013/includes/analysis_print.php).

84 U.S. EIA only provides residential propane prices data for months of January-March and October-December.

propane price since the first quarter of 2014. Residential propane prices in January-March 2022 were, on an average, 25% higher than the first quarter of 2021. However, residential propane prices declined during October-December 2022, averaging 1% below the 2021 average for the same months in 2021.

## TRANSFORMING INFRASTRUCTURE

Overall, electric transmission and natural gas pipeline capacity increased year-over-year from 2021. Most new line-related transmission projects that entered service in 2022 involved upgrades to existing transmission lines and were driven by reliability needs or aging infrastructure. The volume of new solar and battery storage capacity attempting to interconnect to the transmission system has inundated the backlogged generator interconnection queues. Notable natural gas pipeline capacity growth was seen in the South Central and Northeastern United States as a result of natural gas supply and shifts in midstream flows (i.e., natural gas transportation and storage) supporting the growth of LNG exports.

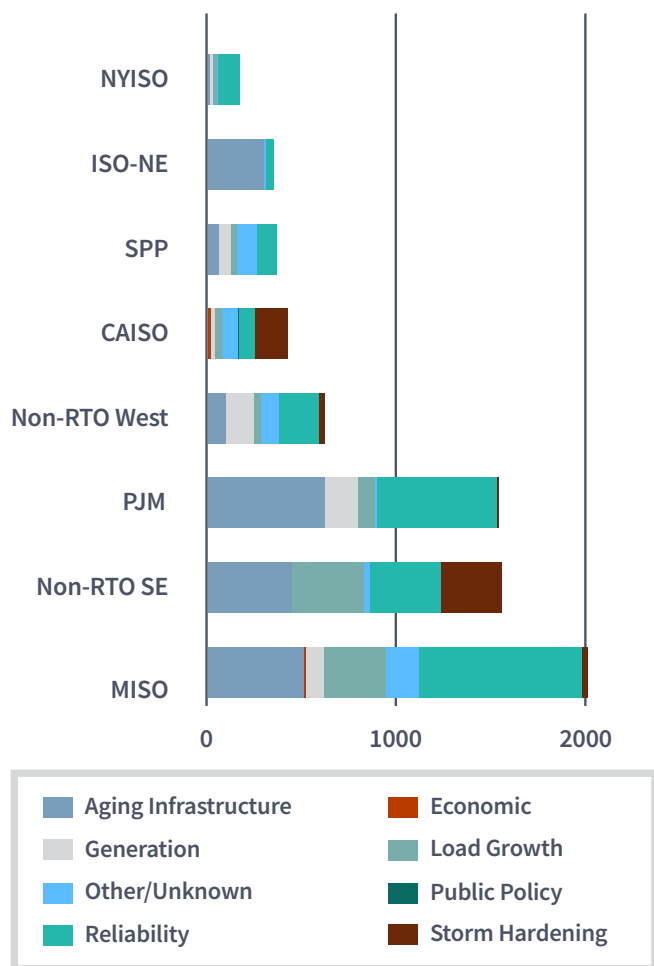
### Electricity Transmission

Public utility transmission providers added new transmission lines, upgraded existing transmission facilities, and planned for future transmission needs in 2022. According to data from C Three LLC, over 800 line-related transmission projects entered service in the U.S. portions of the Eastern and Western Interconnections in 2022. Three fourths of these transmission projects involved upgrades to existing transmission lines. However, approximately a third of all projects included building new lines; of these, approximately a quarter were built at or above 230 kilovolts (kV). Reliability issues and aging infrastructure drove approximately 450 line-related transmission projects that entered service in 2022, while generation needs drove 84 of these projects, economic needs drove four of these projects, and public policy needs drove three of these projects.

In New York, the 20-mile 345 kV Empire State Line entered service in 2022. This new line is designed to better connect renewable energy from the 2,525 MW Robert Moses Niagara Hydroelectric Power Station and other resources near Niagara Falls to Rochester and the rest of NYISO. This \$186 million project, developed by NextEra Energy, Inc., includes a phase angle regulator that will provide additional operational flexibility to the 345 kV system in NYISO. Notably, it was the first transmission project selected through NYISO's Public Policy Transmission Planning Process and is New York's first competitively-bid transmission project. In the west, the 70-mile 345 kV Clearwater Wind Interconnection developed by the Bonneville Power Administration entered service. This project facilitates the interconnection of the Clearwater Wind Project being developed by NextEra Energy by using the existing transmission infrastructure serving the Colstrip Power Plant in Montana. NextEra Energy plans to develop 750 MW of wind nameplate capacity through the Clearwater Wind Project, with the first phase of 350 MW already online by the end of 2022.

In addition, transmission providers in each Order No. 1000 transmission planning region worked towards or completed a regional transmission plan. For example, the SPP Transmission Expansion Plan identified 185 new projects from its integrated transmission planning assessment resulting in 818 miles of new transmission lines and 137 miles of rebuilt lines, costing \$2.21 billion total in engineering and construction outlays. SPP also identified 70 new projects related

**Figure 25 - Line-Related Transmission Projects That Entered Service in 2021, by Region**



Source: North American Electric Transmission and Distribution Project Database, The C Three Group, L.L.C.

to transmission services totaling 137 miles of new transmission lines and 133 miles of rebuilt lines, costing \$494 million total in engineering and construction outlays. MISO's board approved 382 new transmission projects totaling 312 miles of new transmission lines and 526 miles of upgraded lines at a total cost of \$4.3 billion, \$1.3 billion over last year. CAISO's 2022-2023 Transmission Plan identified 16 reliability-driven transmission projects with an estimated cost of \$1.4 billion, six policy-driven projects with an estimated cost of \$1.5 billion, and one economic project – a series reactor installation with a capital cost of \$40 million. CAISO cites the renewable generation and load forecast growth as drivers of the increase in transmission requirements, which dwarf the prior five-year annual average additions to the regional transmission plan of \$217 million.<sup>85</sup>

A few transmission providers also conducted separate forward-looking studies in 2022 to identify the growing transmission requirements that are likely needed due to new generation and load-forecast growth. NYISO's 20-year outlook released in 2022 states that the unprecedented pace of renewable project development requires an increase in the pace of transmission development.<sup>86</sup> MISO approved the first tranche of projects resulting from its Long-Range Transmission Planning effort that develops solutions to provide reliable and economic energy delivery to address future reliability needs.<sup>87</sup> Similarly, in its 20-year outlook released in 2022, CAISO identified transmission requirements totaling more

than \$30 billion split roughly three-ways between upgrades to existing transmission in CAISO's footprint, facilities to integrate offshore wind, and facilities to integrate out-of-state wind.<sup>88</sup> In April 2022, the Commission proposed reforms to its existing regional transmission planning and cost allocation requirements that would require, among other things, all public utility transmission providers to conduct regional transmission planning on a sufficiently long-term, forward-looking basis to meet transmission needs driven by changes in the resource mix and demand.<sup>89</sup>

85 Dev Millstein et al., Lawrence Berkeley National Laboratory, The Latest Market Data Show that the Potential Savings of New Electric Transmission was Higher Last Year than at Any Point in the Last Decade (Feb. 2023), [https://eta-publications.lbl.gov/sites/default/files/lbnl-transmissionvalue-fact\\_sheet-2022update-20230203.pdf](https://eta-publications.lbl.gov/sites/default/files/lbnl-transmissionvalue-fact_sheet-2022update-20230203.pdf)

86 New York ISO, 2021-2040 System & Resource Outlook, (Sept. 2022), <https://www.nyiso.com/documents/20142/33384099/2021-2040-Outlook-Report.pdf>.

87 MISO, Long Range Transmission Planning – Reliability Imperative, <https://www.misoenergy.org/planning/transmission-planning/long-range-transmission-planning>.

88 CAISO, 20 Year Transmission Outlook (May 2022), <http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf>.

89 Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, NOPR, 179 FERC ¶ 61,028.

Some public utility providers in Order No. 1000 transmission planning regions coordinated to identify interregional transmission needs and solutions in 2022. Through their Targeted Market Efficiency Project study, PJM and MISO endorsed one small interregional transmission project that would cost \$0.2 million and is expected to relieve \$7.31 million of future transmission congestion.<sup>90</sup> SPP and MISO conducted a similar Targeted Market Efficiency Project study in 2022; however, for the fifth time, SPP and MISO did not recommend the development of any of the identified projects.<sup>91</sup> SPP and MISO continued with a separate Joint Targeted Interconnection Queue study that will identify transmission projects required to address the significant transmission limitations that restrict the opportunity to interconnect new generating resources near the SPP-MISO seam. In the west, the CAISO Board approved TransWest Express LLC's application to join CAISO as a participating transmission owner; an important step before the 732-mile high-voltage facility can deliver electricity produced by wind farms in Wyoming to the desert southwest. In December 2022, the Commission held a staff-led workshop to discuss whether and how the Commission could establish a minimum requirement for interregional transfer capability for public utility transmission providers in transmission planning and cost allocation processes.<sup>92</sup>

## Electric Interconnection Queues

An unprecedented number of interconnection requests as a byproduct of strong renewable generation and electric storage growth in 2022 continue to prolong generator interconnection queue backlogs. Each interconnection applicant undergoes a series of studies for grid interconnection before it can deliver energy, and the volume of requests have led to both growing lead time and uncertainty in the interconnection process. According to preliminary data from the LBNL, at the end of 2022, the total capacity active in queues have grown to exceed 1,366 GW of generation, 159 GW of hybrid storage and generation, and 325 GW of standalone storage capacity.

The majority of this capacity continues to come from less carbon-intensive sources. Solar, wind, and battery storage resources make up a disproportionate amount of capacity in the queues, with these resources combined making up nearly 94% of the total capacity as of the end of 2022. Solar alone is over half of this capacity. Conversely, new fossil fuel generation makes up a small share of generation in the queues, with only 32 GW of new natural gas capacity entering the queues in 2022 and with 84 GW of natural gas and just over 2 GW of coal capacity remaining in the queues. Furthermore, hybrid resources now comprise a growing share of proposed projects with more than 159 GW of storage capacity being paired with some form of generation (primarily solar + battery).

For a variety of reasons, not every project in the interconnection queue will be built. Historically a minority of proposed capacity was ultimately built with LBNL estimating that only 24% of the projects seeking connection from 2000 to 2020 have subsequently been built.<sup>93</sup> Recently, time spent in the interconnection queues has been

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90 PJM, PJM-MISO IPSAC at 8 (Dec. 2022), <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2022/20221215/ipsac-presentation.ashx>

91 SPP and MISO did not recommend any of the identified projects because the identified projects were displaced by a regional project, would have predominately benefited a single region, or would have exceeded the pre-established \$20 million cost cap for Targeted Market Efficiency Projects. SPP, Draft 2022 MISO-SPP Coordinated System Plan Study Report (Dec. 2022).

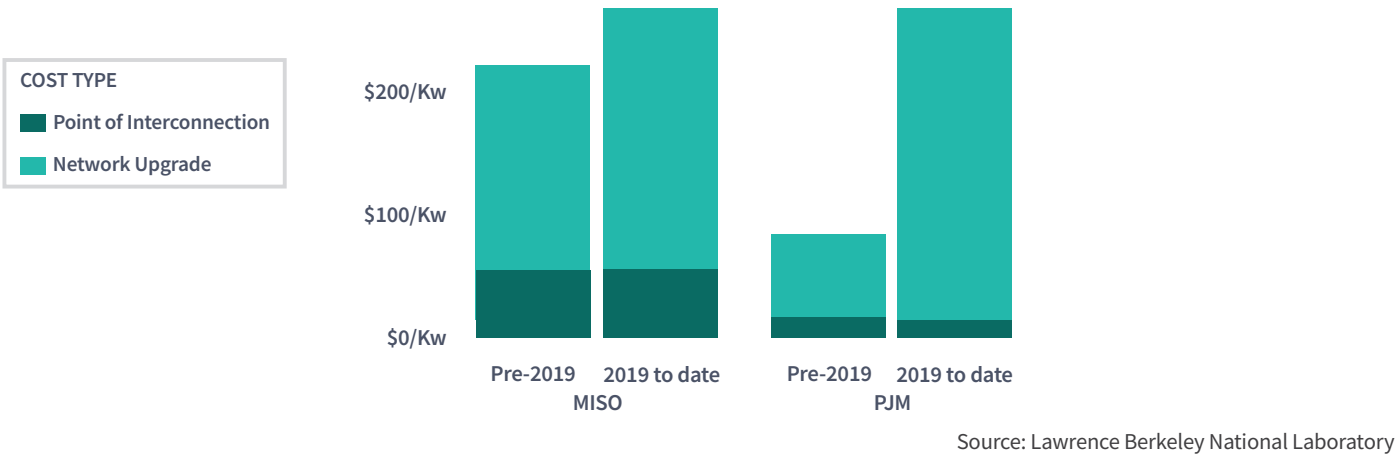
92 Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements, Notice of Staff-Led Workshop, Docket No. AD23-3-000 (Oct. 6, 2022).

93 Joseph Rand et al., Lawrence Berkeley National Laboratory, Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2021 (April 2022), [https://emp.lbl.gov/sites/default/files/queued\\_up\\_2021\\_04-13-2022.pdf](https://emp.lbl.gov/sites/default/files/queued_up_2021_04-13-2022.pdf)

rising. LBNL estimates that the typical duration from interconnection request to commercial operation increased from 2.1 years for projects built in 2000-2010 to 3.7 years for those built in 2011-2021. Applicants that are currently active or have withdrawn from the interconnection queue typically have higher interconnection costs compared to projects that have completed all interconnection studies according to data on PJM and MISO from LBNL.<sup>94</sup> The costs to interconnect have grown substantially over time with the cost of broader network upgrades driving nearly all this growth as shown in Figure 26. This data also shows that interconnection costs for wind, storage, and solar are higher than for natural gas on average.

Transmission providers continue to look to possible solutions to address generator interconnection queue backlogs. Several transmission providers have moved toward cluster studies that allow multiple projects to be studied simultaneously. In June 2022 the Commission proposed several reforms to the generator interconnection process to implement a first-ready, first-served cluster study process, increase the speed of interconnection queue processing, and incorporate technological advances into the interconnections process.<sup>95</sup>

**Figure 26 – Average Costs to Interconnect, PJM and MISO Sample**



## Natural Gas Pipeline and Storage Certification

Over the past five years, Commission-jurisdictional pipeline capacity additions went in service across every major region of the contiguous United States. Such incremental capacity additions ranged nationwide from a high of 19.7 Bcfd in 2018 down to a low of 5.0 Bcfd in 2022 – a 38% year-over-year decline from 8.1 Bcf in 2021. Pipeline capacity additions in recent years may result from natural gas supply and shifts in midstream flows due to increased LNG exports and other factors.

More than 40% of the incremental pipeline capacity additions over the last five years are located in the South-Central region, which includes states along the Gulf Coast. In 2022, incremental pipeline capacity additions in the South-Central region made up 58% of capacity additions. Notable South-Central additions include Kinder Morgan Energy

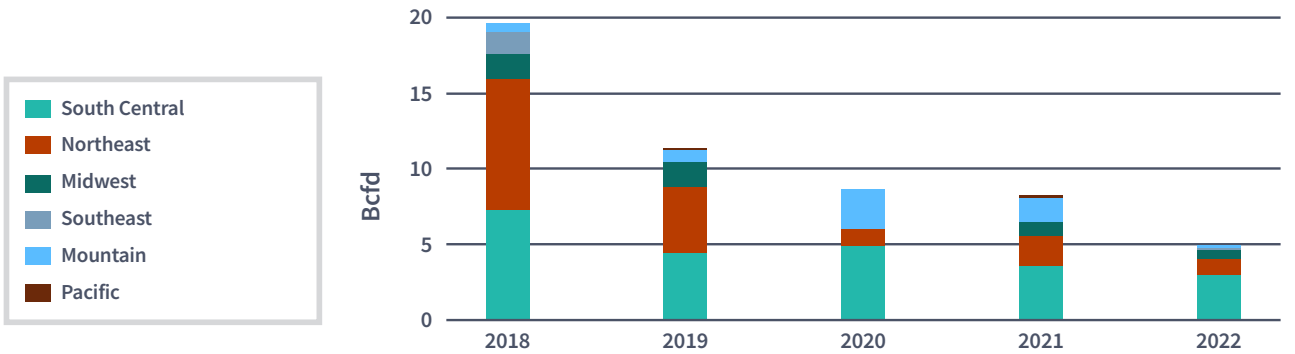
94 Lawrence Berkeley National Laboratory, Generator Interconnection Costs to the Transmission System (Accessed February 2022), [https://emp.lbl.gov/interconnection\\_costs](https://emp.lbl.gov/interconnection_costs)

95 Improvements to Generator Interconnection Procedures and Agreements, NOPR, 179 FERC ¶ 61,194.

Partner’s Acadiana expansion project in Louisiana and Columbia Gulf Transmission’s Louisiana Xpress expansion project which goes from Kentucky to Louisiana. Northeast incremental pipeline capacity additions account for over 34% of capacity additions over the last five years and 22% of capacity additions in 2022.

Unlike pipelines, little new natural gas storage capacity under Commission jurisdiction has begun service in more than a decade. In 2022, the Commission certificated a project in Louisiana with 20 Bcf storage capacity which will be the first significant addition in natural gas storage since the 2010s when it becomes operational in 2024. Significant buildout of natural gas storage capacity has not been observed since the first half of the 2010s – this buildout helped reduce large seasonal price swings that were common before wide-scale extraction of shale natural gas in the United States began in the late 2000s. Reduced reliance on storage as a source of supply during periods of elevated demand, due to higher levels of natural gas production in close proximity to consuming markets in the Northeast and Midwest, and the lower seasonal difference between the price of winter and summer natural gas have contributed to less need for incremental natural gas storage capacity.<sup>96</sup>

**Figure 27: U.S. Interstate Natural Gas Pipeline In-Service Capacity Additions by Region**



Source: U.S. EIA

## MAJOR EVENTS

Extreme weather may constrain electricity supply by degrading the infrastructure needed for the production and distribution of electricity and natural gas. In 2022, two extreme weather events, the western heat wave (August 31-September 9) and a winter storm (December 23-25), presented reliability challenges on a regional basis. In contrast to the Southeast—in particular, Tennessee and North Carolina—where power failures were widespread during the winter storm, the western power grid remained resilient through the western heat wave.

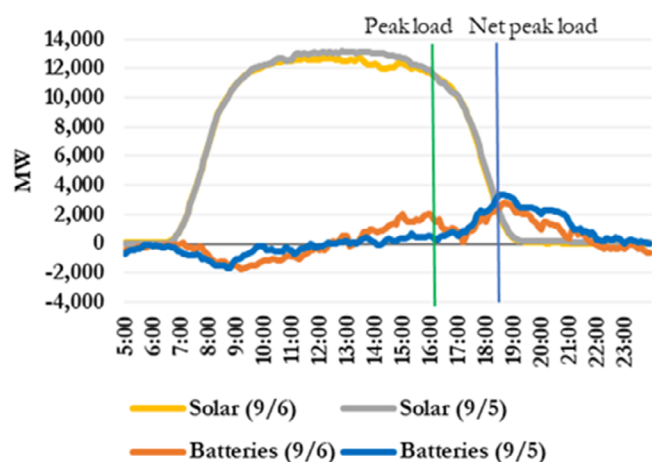
## Western Heat Wave

Since the summer of 2020, CAISO and other balancing authorities in the WECC have pursued enhancements to prepare for heat waves that lead to sustained levels of high electric demand, with some of those enhancements taking effect

96 EIA, *U.S. natural gas storage capacity increased slightly in 2016*, April 4, 2017, <https://www.eia.gov/todayinenergy/detail.php?id=30632>



**Figure 28: CAISO Battery Storage and Solar Output on September 5 & 6, 2022**



Source: CAISO website

in CAISO in 2021 and 2022. From August 31 through September 9, 2022, the western United States experienced record-setting heat that resulted in an all-time high load in both the WECC and CAISO.<sup>97</sup> Despite the heat wave, CAISO was able to maintain system operations without interruption unlike in August 2020, when CAISO shed firm load on two days in August. Since that 2020 August event, CAISO has made a number of enhancements that likely contributed to successfully meeting challenging system conditions. These changes and enhancements included: (i) increased capacity through resource adequacy procurement, including from battery storage; (ii) the use of new state programs to make non-market resources available to handle extreme events; (iii) close coordination with load-serving entities during CAISO’s highest emergency level; (iv) market enhancements implemented since summer 2020;<sup>98</sup> and (v) enhanced coordination, awareness, and communication internally in CAISO and between balancing authorities, investor-owned utilities, publicly-owned utilities, business and consumer groups, California regulatory agencies, and the Governor’s Office.<sup>99</sup>

In its post-event analysis, CAISO noted that battery storage resources helped CAISO to manage the high electricity demand during the heat wave by providing flexible capacity in the CAISO market, as those battery storage resources injected power onto the grid during critical hours when solar output was declining.<sup>100</sup> Figure 28 displays MW output from battery storage and solar in CAISO on September 5 and 6. On both days, when CAISO “net load” reached had its peak—that is, when load minus renewable generation is highest—battery storage output was at or near its highest level. Notably, battery storage resources were discharging energy even before solar generation had declined between 4:00pm and 6:30pm PST, reflecting the unusually high loads on both days.

## December 2022 Winter Storm

Extreme winter weather on December 23-25, 2022, increased natural gas and electricity demand across the United States, as low temperatures constrained the production and supply of natural gas. Power outages affected more than 1.5 million consumers, predominantly in the Southeast.<sup>101</sup> Daily U.S. natural gas demand set a record on December

97 CAISO, *Summer Market Performance Report for September 2022*, November 2, 2022, pg. 12, <http://www.caiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf>.

98 A list of recent reforms and enhancements that played a role in maintaining system reliability are provided in CAISO, *Summer Market Performance Report for September 2022*, November 2, 2022, pp. 18-20.

99 Id., at 13.

100 CAISO, *Summer Market Performance Report for September 2022*, November 2, 2022, section 9, <http://www.caiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf>.

101 S&P Global Spotlight, *U.S. Gas Production Poised for Swift Recovery after 9% Drop on Week* (December 28, 2022), <https://benport.spglobal.com/spotlight/2022/12/us-gas-production-poised-for-swift-recovery-after-9-drop-on-week/>.

23, 2022, when it reached 155.7 Bcfd, surpassing the previous single-day record high of 150.2 Bcfd set on January 30, 2019.<sup>102</sup> The cold weather led to wellhead freeze-offs resulting in a 15% decline in production from 97.2 Bcfd on December 20 to 82.7 Bcfd on December 25. Total U.S. domestic natural gas consumption averaged 104.6 Bcfd in December 2022, up 28.3% from the average of the eleven months prior and up 12.8% from the average in December 2021. As natural gas production declined and consumption increased, natural gas storage withdrew rapidly to meet demand contributing to high natural gas prices and in turn high electricity prices during this extreme winter weather event. On December 28, 2022, FERC and NERC announced a plan for a joint inquiry into the bulk power system operations during the winter storm.<sup>103</sup> The joint inquiry will aim to identify performance issues and, where appropriate, recommend solutions to address those issues.

FERC initiated two rulemakings in 2022 aimed at improving the reliability of the bulk power system against the threats of extreme weather. The first proposed rulemaking would direct NERC to revise the Transmission System Planning Performance Requirements to address reliability concerns pertaining to transmission system planning for extreme heat and cold weather events. The second proposed rulemaking would direct transmission providers to submit one-time reports describing their policies and processes for conducting extreme weather vulnerability assessments and identifying mitigation strategies.

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<sup>102</sup> Id.

<sup>103</sup> NERC, Newsroom, *FERC, NERC to Open Joint Inquiry into Winter Storm Elliott* (December 28, 2022), <https://www.nerc.com/news/Pages/FERC,-NERC-to-Open-Joint-Inquiry-into-Winter-Storm-Elliott.aspx>.

## CONCLUSION

Wholesale electricity and natural gas prices increased in most markets in 2022 for the second consecutive year with limited exceptions. Various factors including higher electricity demand and higher natural gas prices placed upward pressure on wholesale electricity prices. Higher natural gas prices in 2022 were driven by various factors including increased demand during the summer, with warmer-than-normal temperatures across most of the country and a tight international market due to global demand for LNG, as well as lower-than-normal natural gas storage inventories going into the winter. While annual average prices of natural gas increased year-over-year in 2022, natural gas prices fell in the fourth quarter in most regions except California and New England where prices remained above the Henry Hub annual average of \$6.38/MMBtu.

Most generation capacity additions came from wind and solar resources and most retirements came from coal resources. Electric transmission and natural gas pipeline capacity increased year-over-year in 2022. Wholesale electricity market arrangements expanded with the launch of the SEEM, as well as the expansions of the WEIM and the WEIS.

Extreme weather stressed the power grid in 2022. A record-setting heat wave in the western United States lasting over one week towards the end of the summer drove electricity demand in both the Western Interconnection and CAISO to an all-time high. Despite the heat wave, CAISO maintained uninterrupted system operations. In late December, a winter storm, another extreme weather event, impacted the mid-continental and eastern United States and triggered power outages, mainly in the Southeast. On December 28, FERC and NERC announced a plan for a joint inquiry into the bulk power system operations during this winter storm to identify performance issues and, where appropriate, recommend solutions.