FEBRUARY 2024

ENERGY VENTURES ANALYSIS

Operation of the U.S. Power Grid During the January 2024 Storm

Prepared for:

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ENERGY VENTURES ANALYSIS

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Executive Summary

The North American winter storm spanning January 13–21, 2024, called the Jan ’24 Winter Storm or storm in this report, profoundly impacted the continental United States. Between January 13 and 21, multiple cold weather fronts moved across the country, setting low-temperature records across the Central, Southern, and Eastern United States. (This report refers to these multiple weather fronts as a single winter storm.) The massive temperature drop rapidly increased heating demand, met primarily by electricity or natural gas. Due to previous experience with grid reliability issues during Winter Storm Elliott in December 2022, Winter Storm Uri in December 2021, and the August 2023 heatwave, the utility response reflected better preparedness and more effective coordination. Once again, dispatchable power generation, such as natural gas and coal, increased electricity generation to meet the heightened demand. Wind generation faced challenges with fluctuation and dropped during peak demand hours, while solar generation was entirely or almost entirely absent during peak electricity demand hours.

This report analyzes and highlights how power generation across the country responded to the exceptional winter weather event in January 2024. Some of the national and regional highlights of the report include:

- The **January 2024** winter storm set new **single-day electricity demand records in SPP and ERCOT**. The storm set records for the **second-highest** electricity demand **in the Southeast** (after Winter Storm Elliott), the **third-highest in PJM**, and the **fourth-highest in MISO**.
- On a total regional level (the sum of all affected power market regions – SPP, MISO, ERCOT, PJM, and the Southeast)**, coal and natural gas provided the bulk of incremental electricity** during the peak of the extreme cold on January 17. Due to highly favorable wind conditions, electricity from wind turbines also increased compared to the first two weeks of 2024.
- Compared to the generation mix during the peak demand day during Winter Storm Elliott in 2022, wind generation increased a staggering 20 GW due to favorable wind speed conditions. Noteworthy, wind capacity added between December 2022 and January 2024 in the affected regions totaled less than 6 GW, with the remaining 14 GW of increased wind generation due to **much more favorable wind speed conditions than during Elliott**, especially in MISO. Without the favorable wind conditions during the January 2024 storm, widespread power outages would have been likely to occur.
- **During peak electricity demand hours** in ERCOT and other regions, **solar facilities provided zero or near-zero electricity** as the peak demand hours occurred during nighttime hours. Higher shares of solar facilities and fewer dispatchable resources likely would have resulted in widespread power outages.
- **The response of natural gas-fired electric generating resources** to the sudden increase in electricity demand was **significantly improved** from the challenges experienced during winter storms Uri and Elliott. Initial analysis indicates better coordination between natural gas and power system operators, along with much lower natural gas production losses during and faster production recovery after the storm assisted in increasing the operations of these resources during the January 2024 winter storm.

Recent and future changes in electricity supply across the country have resulted in and will exacerbate the challenges ISOs and utilities experienced during the latest round of winter storms. These challenges and risks include but are not limited to the following:

- While electricity demand usually peaks in the summer, the risk of electricity supply failures is most significant during winter peak events, like the January 2024, Elliott (December 2022), and Uri (February 2021) winter storms. The reason is that natural gas has grown to be the largest source of U.S. power supply (42% in 2023), and the demand for natural gas for home heating surges during cold weather at the same time as electricity demand. Even with “firm” pipeline transportation contracts (the “gold standard”), some power plants have been unable to receive enough natural gas at sufficient pipeline pressure to operate during extreme winter cold weather. Notably, improved winterization and better coordination between natural gas and power system stakeholders (e.g., earlier scheduling of natural gas deliveries), both of which have been key recommendations put forth by the Gas Electric Harmonization Forum (GEHF)[1], resulted in fewer natural gas plant unplanned outages during the January 2024 winter storm compared to Winter Storm Elliott.

- Natural gas power plants do not maintain on-site gas storage (although some plants have fuel oil backup) and are not available to meet increased power demand if gas deliveries cannot increase to match increased demand. Exploring on-site LNG storage options for natural gas plants, as explored by electric utilities across the country, including Dominion Energy in Virginia[2], will improve the reliability of natural gas-only power plants during these extreme weather events.
- The only form of power generation that can increase output significantly (known as “dispatch”) to meet high electricity demand is powered by fossil fuels (coal, natural gas, and oil). The growing supply of wind and solar power can only operate when the wind blows or the sun shines. These power sources almost always operate at maximum capacity when available because of their low operating costs and, as a result, cannot increase output further when demand increases. Similarly, because of low costs, nuclear power plants are operated at maximum capacity when available. Hydropower can be managed to increase output to meet demand where there is a sufficient reservoir or pumped storage capacity, but this is a very limited supply.
- Over the last decade, the U.S. power industry has steadily replaced dispatchable fossil fuel generation capacity with on-site fuel storage (i.e., coal and oil) with non-dispatchable intermittent solar and wind resources. Driven by federal and state mandates and subsidies, this replacement will accelerate over the next decade, increasing the likelihood of system failures during extreme winter weather events. Proposed battery energy storage systems are not equipped to provide electricity for periods lasting longer than 4 to 8 hours, which is inadequate during extended high electricity demand events. Additionally, further research and real-life observations are needed to assess the operational reliability of large utility-scale battery systems during ambient air temperatures outside their designed temperature range.
- Once again, the coal power fleet was a principal source of increased power generation to meet demand during the January 2024 winter storm. However, another 98 GW of coal-fired generation capacity, or more than half of the currently operational coal fleet, is announced to retire by 2035. Massive renewable capacity buildouts driven by financial incentives included in the 2022 Inflation Reduction Act and proposed or currently litigated federal environmental regulations like the 2023 proposed Greenhouse Gas Rule[3] or the Good Neighbor Plan[4] are likely to force additional coal retirements or accelerate the ones already announced or planned. Without adequate and comparable replacement capacity, electric power system failures across the United States are more likely during similar extreme weather events.

[1] https://www.naesb.org/pdf4/geh_final_report_072823.pdf
[2] https://virginiamercury.com/2024/01/24/utilities-plan-onsite-gas-storage-to-improve-reliability-critics-warn-of-costs-safety-concerns/
[3] https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power
[4] https://www.epa.gov/Cross-State-Air-Pollution/good-neighbor-plan-2015-ozone-naaqs

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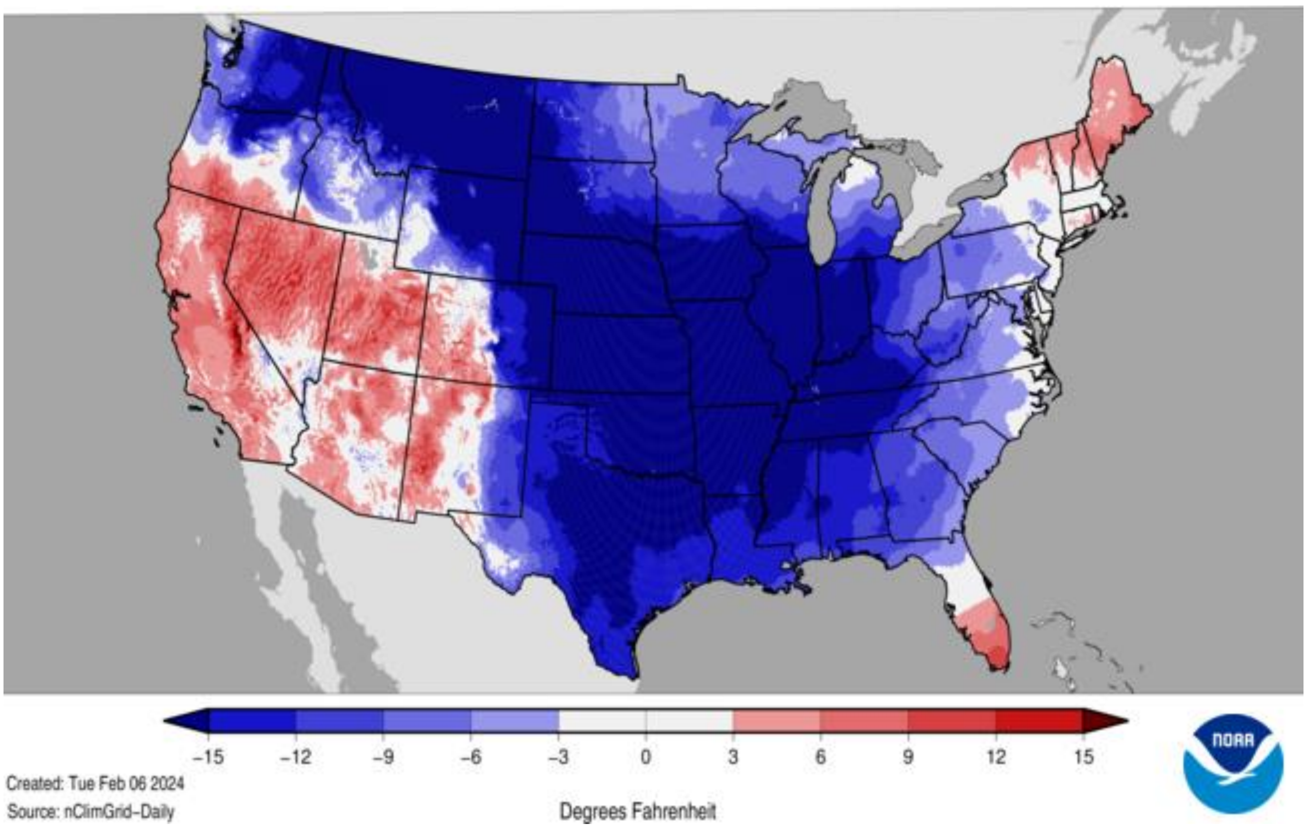
Table of Exhibits

Introduction

The North American winter storm spanning roughly January 13–21, 2024 (with high regional variance in the days affected) left a profound impact across the continental United States, with notable repercussions felt particularly in the Southern regions. Originating as an extratropical cyclone in the northeastern Pacific Ocean on January 12, the system made landfall the next day. It ushered in heavy snowfall and unusual ice accumulations closer to the coastline. Subsequently, the storm weakened over the Rocky Mountains, and the remaining energy, coupled with an arctic front near the Gulf Coast, resulted in wintry precipitation in atypical locations like Texas and Louisiana. The system then consolidated and slightly intensified, moving northwards towards the Mid-Atlantic states.

EXHIBIT 1: MINIMUM TEMPERATURE DEPARTURES FROM AVERAGE (JAN 14, 2024 – JAN 20, 2024)



This winter storm had far-reaching and substantial impacts coast to coast in the U.S., affecting regions unaccustomed to frozen precipitation. The drop in temperatures led to a rapid increase in heating demand. Dispatchable power generation, such as natural gas and coal, stepped up production to meet the heightened demand, while wind generation faced challenges due to fluctuations.

Regional Analysis

Using EIA's regional data from the Hourly Electric Grid Monitor, EVA performed analyses of the impact and performance of the power market regions shown in **EXHIBIT 2**.[5,6] The power market regions are presented in the order of the winter storm's impacts on their respective power systems.

EXHIBIT 2: MAP OF POWER MARKET REGIONS

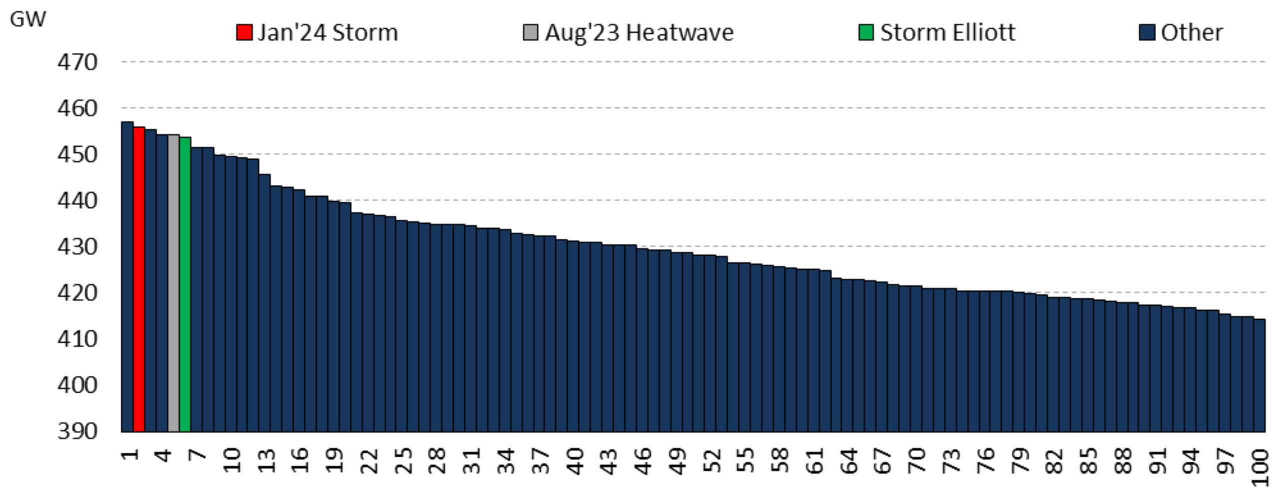
Regional Aggregate Results

During the period spanning from January 13th to January 21st, 2024, a significant portion of the affected Lower 48 states experienced notably subpar temperatures, causing an escalation in power demand. **EXHIBIT 3** highlights the top 100 electricity demand occurrences across the combined territories of SPP, MISO, PJM, ERCOT, and Southeast ("Regional Total"). The winter storm of January 2024 prompted the second-highest electricity demand (456 GW), exceeding the regional average by nearly 100 GW, approximately 350 GW. Noteworthy parallels exist between the August heatwave and Winter Storm Elliott, with demand levels trailing merely 1.5 GW below those recorded during the January 2024 winter storm.

[5] Northeast = EIA Grid Monitor regions NY & NE; PJM = MIDA; Southeast = TEN, CAR, SE & FLA; MISO = MIDW; ERCOT = TRE; SPP = CENT; WECC = NW, SW & CAL. Further detail on which balancing authorities make up the EIA regions can be found here: https://www.eia.gov/electricity/930-content/EIA930_Reference_Tables.xlsx

[6] WECC & Northeast are excluded from the report as the data analysis showed little impact on the WECC or Northeast power systems during the January 2024 winter storm.

EXHIBIT 3: REGIONAL TOTAL - TOP 100 ELECTRICITY DEMAND DAYS

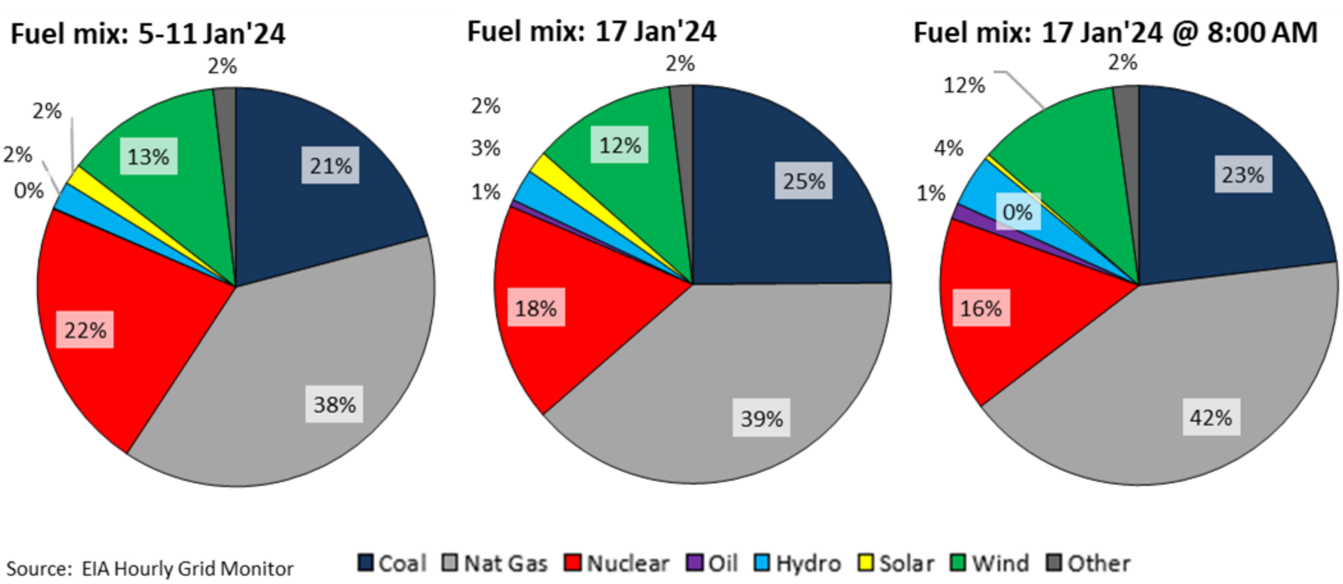


Source: EIA Hourly Grid Monitor

On the broader scale, the peak demand during the storm occurred on January 17th, notably peaking at 8:00 am. Analyzing the generation dynamics for the impacted region under regular winter days from January 5th to January 11th, 2024, reveals a prevailing reliance on natural gas and nuclear sources, succeeded by coal and wind. While the overall fuel mix during the peak demand day of January 17th exhibited relative consistency with the average, there was a modest uptick in coal and gas generation, as shown in **EXHIBIT 4**.

At the peak hour, coal generation fulfilled approximately one-fourth of the demand, with wind resources maintaining a steady 12% contribution to the generation mix. Notably, the hydro share doubled during this interval, and natural gas experienced intensified utilization, emerging as the predominant contributor to the generation mix, commanding a significant 42% share of the total generation output.

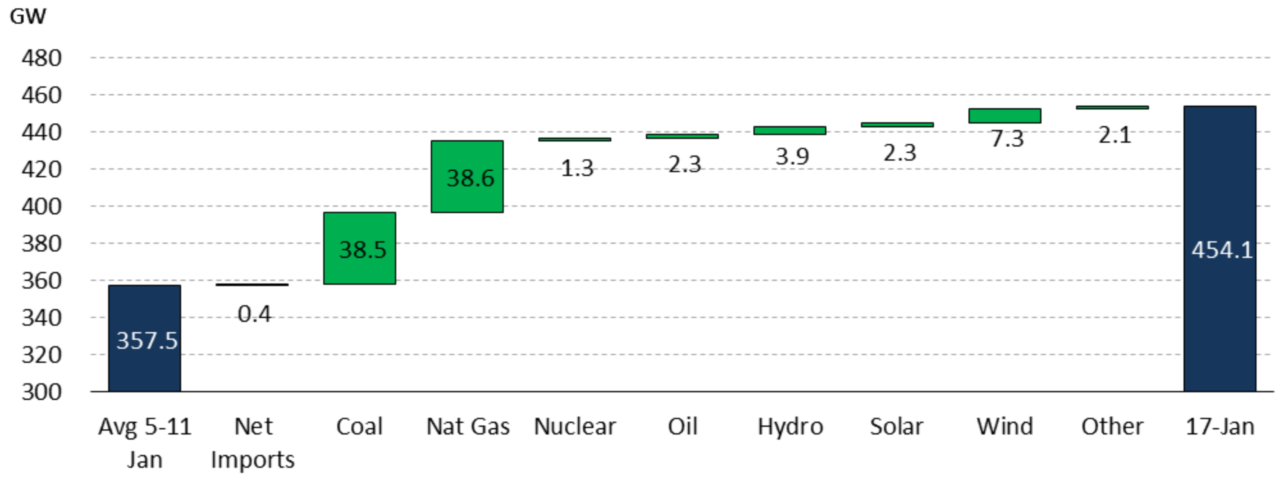
EXHIBIT 4: REGIONAL TOTAL - GENERATION MIX



Source: EIA Hourly Grid Monitor

The demand amidst the January 2024 winter storm peaked on the 17th of January, triggering an increased power demand of nearly 100 GW in contrast to a typical winter week. Approximately 80% of this heightened demand was met through fossil generation, predominantly facilitated by coal and gas, each contributing approximately 39 GW, as shown in **EXHIBIT 5.** Renewable sources accounted for the residual portion necessary to satisfy the increased demand.

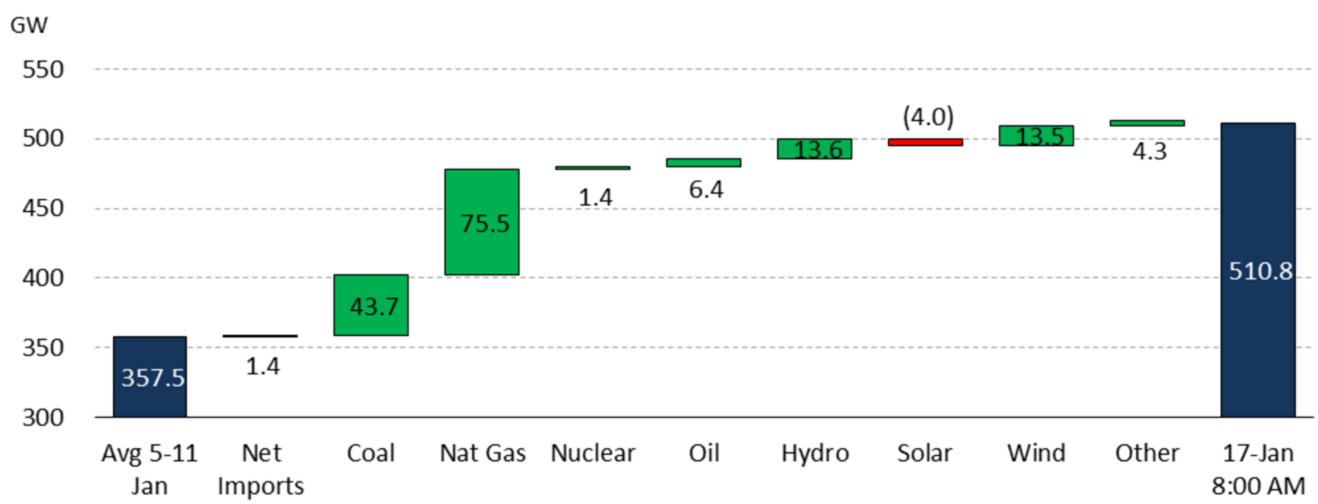
EXHIBIT 5: REGIONAL TOTAL - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY



Source: EIA Hourly Grid Monitor

In the peak demand hour of the winter storm, the demand surged by approximately 150 GW in contrast to a standard winter week. Given the timing of the peak at 8:00 AM, solar capacity was insufficient to contribute significantly to this escalated demand. Both wind and hydropower experienced substantial increments in generation, contributing 60 GW and 22 GW, respectively. Notably, fossil fuel sources met most of the heightened demand, with natural gas providing an additional 76 GW and coal contributing another 44 GW compared to a typical winter week, as shown in **EXHIBIT 6**.

EXHIBIT 6: REGIONAL TOTAL - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR

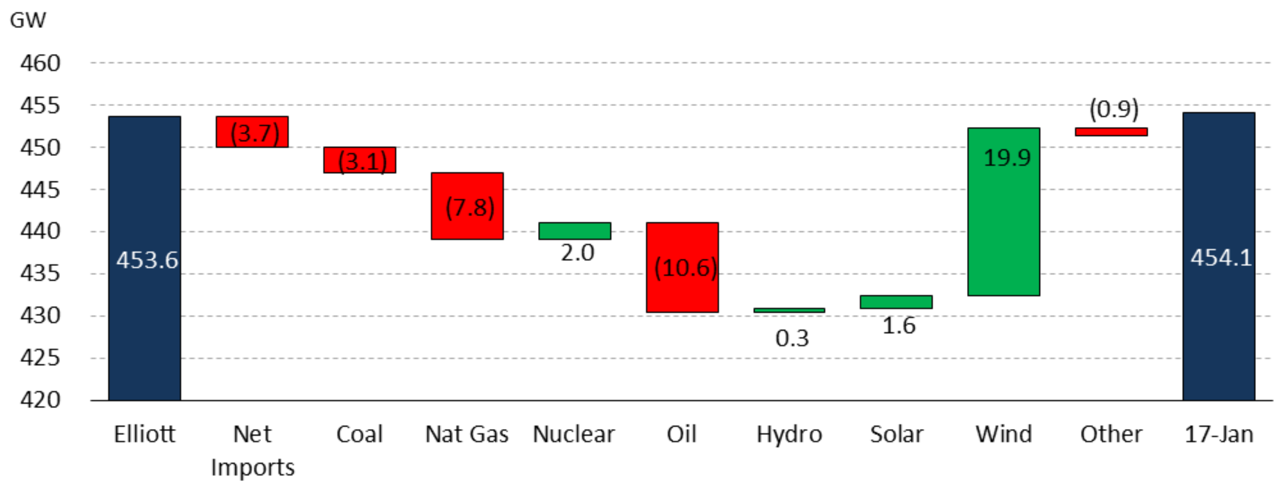


Source: EIA Hourly Grid Monitor

EXHIBIT 7 shows the demand and generation dynamics observed during both Winter Storm Elliott and the January 2024 winter storm. Notably, while the demand exhibited remarkable similarity across both periods, the composition of the generation mix starkly differed.

During Storm Elliott, hourly wind generation registered at 34 GW, contrasting with the more robust 53 GW recorded during the January 2024 winter storm. Furthermore, nuclear generation exceeded Storm Elliott's levels by 2 GW. These contributions from renewable sources, complemented by a modest increase in solar generation, lead to a reduction in fossil fuel-based generation during the peak of the January 2024 winter storm compared to the Storm Elliott period. In the latter, the deficit was compensated for by a combined reliance on natural gas, coal, oil, and imports.

EXHIBIT 7: REGIONAL TOTAL - ELLIOTT'22 DEMAND VS. PEAK JANUARY'24 DEMAND



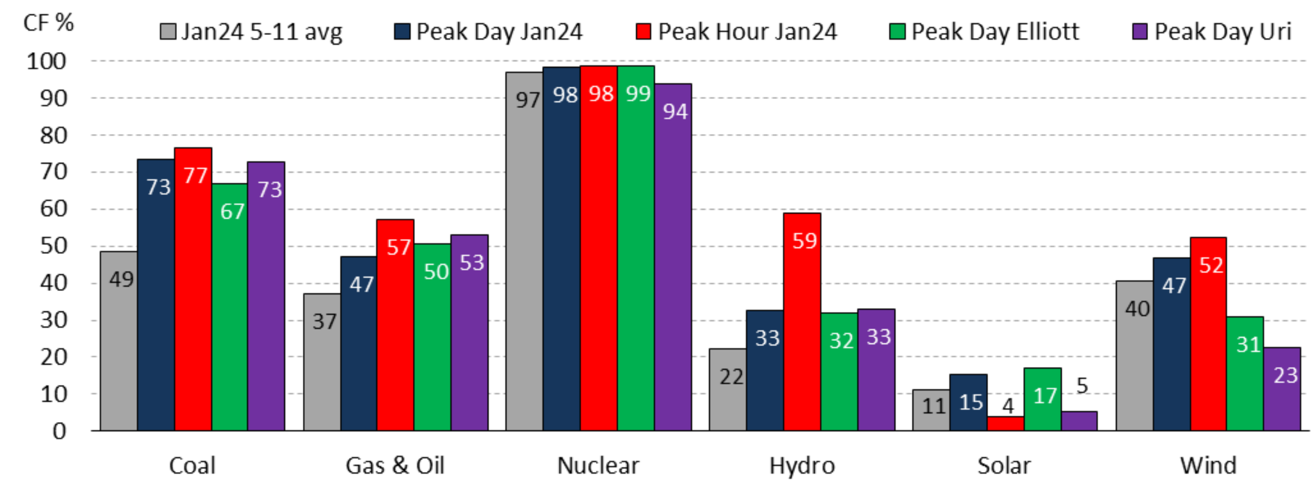
Source: EIA Hourly Grid Monitor

EXHIBIT 8 shows the capacity factor or utilization rates of the different types of generating resources during various periods of peak demand compared to the second week of January 2024. The capacity factor automatically adjusts for any resource additions or retirements that happened between the occurrences of the winter storms analyzed. Therefore, any difference between the January 2024, Elliott, and Uri winter storms is due to the availability or dispatch of the various resources. The capacity factors shown in **EXHIBIT 8** are an average of all operational generating resources of that fuel type, regardless of a unit's actual availability during the observed period.[7]

Across the three storms, coal-fired power plants have shown the most significant increase in utilization rate across the different types of generating resources (excluding nuclear power plants, which, in the U.S., operate at 100% utilization around the clock when available). Natural gas-fired power plants, albeit reporting increased availability during the January 2024 winter storm compared to Elliott and Uri, show a slightly lower fleetwide capacity factor during the peak electricity demand day, most likely due to massively increased wind generation, which required fewer gas generators to fill the void. As mentioned, the wind turbine capacity factor saw a massive increase during the January 2024 winter storm compared to Elliott and Uri on the peak demand day of each storm, as the latest storm included higher and more sustained wind speeds, allowing for increased wind generation in crucial areas. Also worth noting is the abysmal capacity factor of solar facilities during these winter storms, especially during the peak demand hour. The fleetwide capacity factor for solar facilities during the January 2024 winter storm was just 4% during the peak demand hour, with two of the five regions analyzed (SPP and ERCOT) registering zero or near-zero solar generation during their respective peak demand hours.

[7] For example, if unit A operated at 100% and unit B was offline (i.e., 0%), the fleet average capacity factor would be 50%.

EXHIBIT 8: REGIONAL TOTAL - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



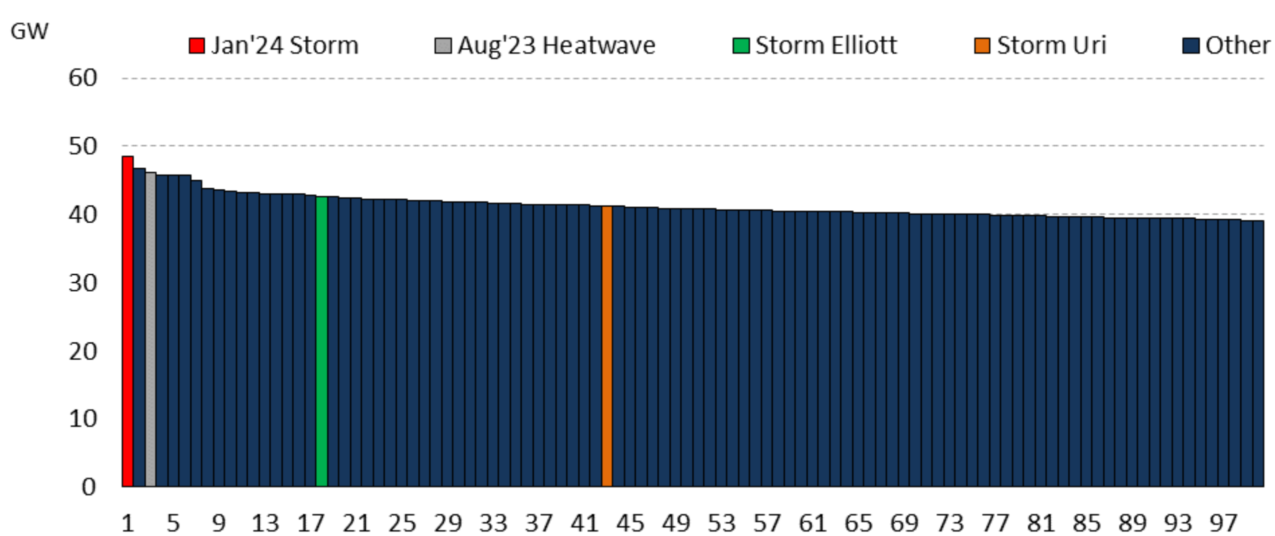
Source: EIA Hourly Grid Monitor & EIA 860 data; *Uri data only refers to MISO, SPP, and ERCOT regions

Southwest Power Pool

The Southwest Power Pool (SPP) is an independent system operator responsible for managing the bulk electric grid and wholesale power market across a vast expanse of the central United States and serves nearly 19 million customers spanning 17 states, from North Dakota to Louisiana.

During the winter storm of January 2024, SPP faced unprecedented demand, marking its highest peak in history. This surge surpassed all previous daily peaks, including those experienced during notable events such as Storm Elliott and Storm Uri. Notably, the average hourly demand during this period reached 48.5 GW, surpassing the levels observed during the August 2023 heatwave by 1.5 GW, a significant margin. **EXHIBIT 9** provides an illustrative representation of the top 100 demand days encountered within the SPP region.

EXHIBIT 9: SPP - TOP 100 ELECTRICITY DEMAND DAYS

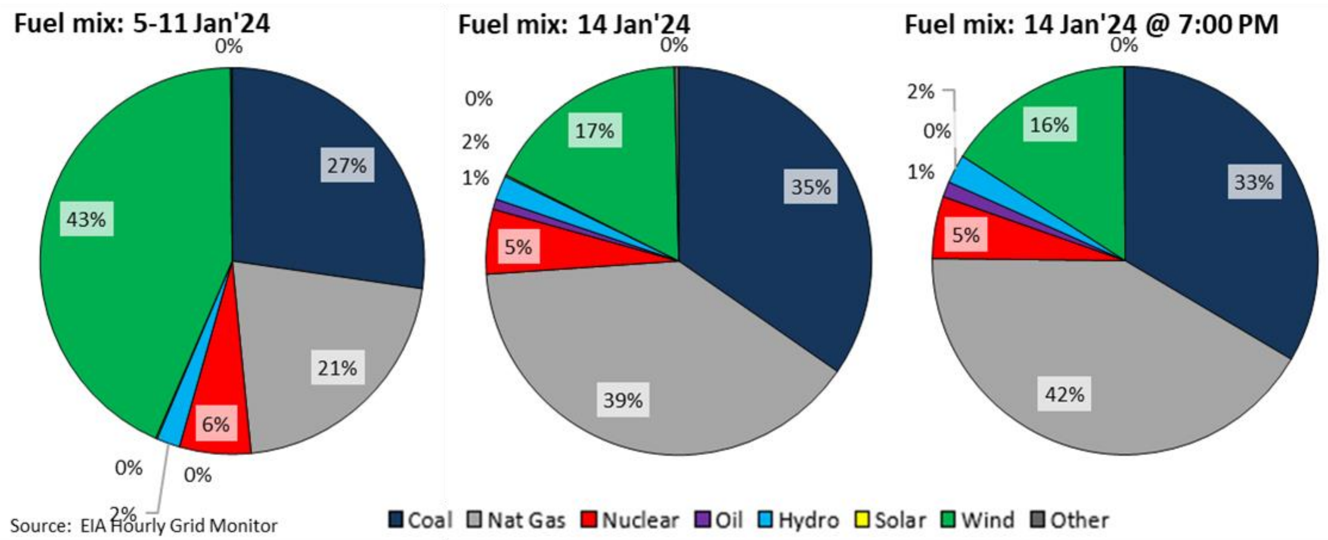


Source: EIA Hourly Grid Monitor

Wind resources consistently hold the predominant share of generation in SPP during regular weather conditions. The evident growth in wind capacity expansion over recent years is readily noticeable, as depicted in the first pie chart presented in **EXHIBIT 10** below. During the week spanning from January 5th to January 11th, 2024, wind generation accounted for an impressive 43% of the total generation mix, outpacing coal and gas by a substantial margin exceeding 15% each. There was a surge in demand from 33.8 GW to 48.5 GW due to inclement weather.

The average hourly wind generation plummeted from 14.7 GW to 6.5 GW between a typical and peak demand day, representing a significant decline of nearly 60% in the wind generation mix. On the day of peak demand, wind contributed a mere 17% to the generation mix, prompting coal and gas to ramp up their output to meet the heightened demand, as shown in the second and third pie charts below.

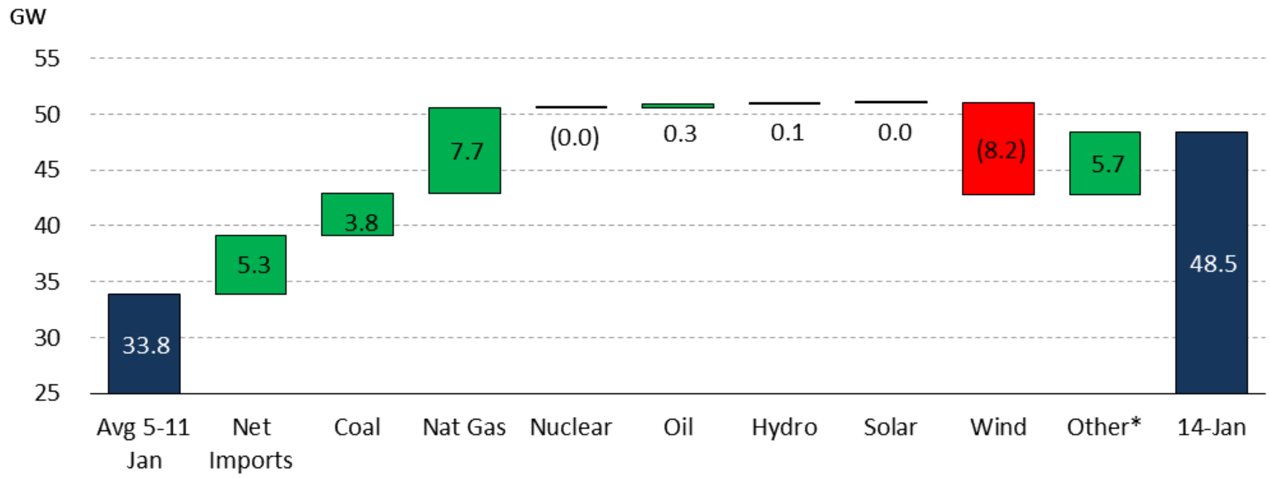
EXHIBIT 10: SPP - GENERATION MIX



Source: EIA Hourly Grid Monitor

EXHIBIT 11, presented below, offers a comparative analysis of demand and generation from various fuel sources between a regular winter week at the beginning of 2024 and the peak January 2024 storm day within SPP. Notably, with demand escalating by 15 GW on January 14th, net electricity imports surged by over 5 GW. In response to a reduction in wind generation by more than 8 GW, coal and gas generation showed a marked increase to ensure grid reliability. Coal generation ramped up by 3.8 GW, while gas generation increased by 7.7 GW, effectively compensating for the shortfall and maintaining the integrity of the grid.

EXHIBIT 11: SPP - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY

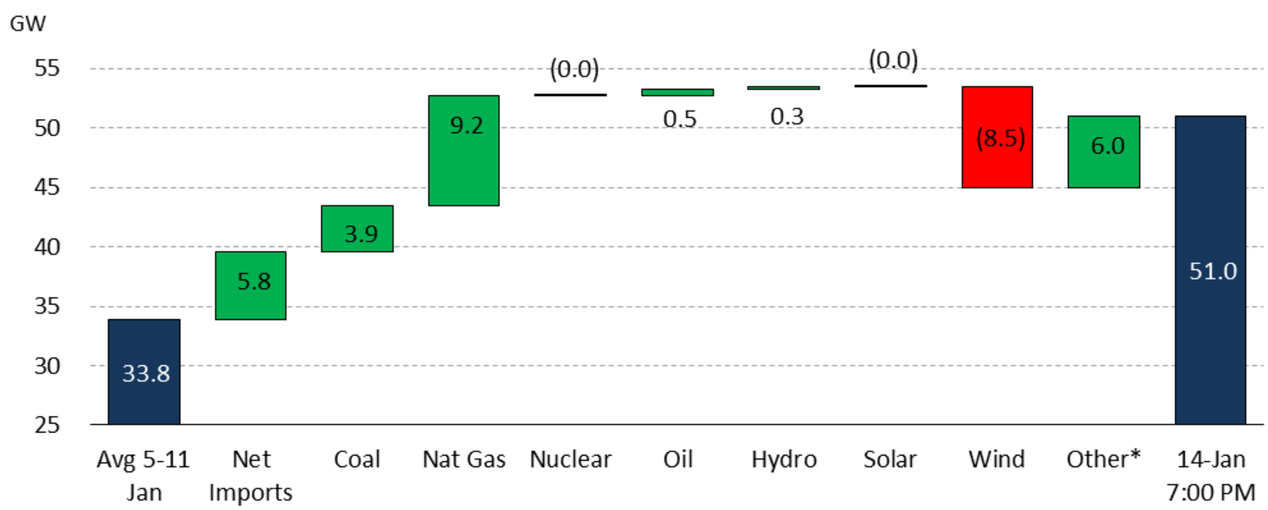


Source: EIA Hourly Grid Monitor; *"Other" includes unaccounted generation to meet demand

Similar to the above waterfall chart, the chart presented in **EXHIBIT 12** below offers a comparative analysis between a regular winter week and the peak hour of the January 2024 winter storm, which marked the peak of demand within SPP. Notably, this peak hour occurred at 7:00 PM on January 14th, coinciding with a surge in electricity demand to 51 GW.

During this critical hour, wind generation experienced a notable reduction of 8.5 GW, yielding a mere 6.2 GW compared to its standard hourly generation of 14.7 GW. To offset this deficit, natural gas and coal resources were swiftly called upon to bridge the supply gap. Natural gas generation surged to 16.4 GW during the peak hour, representing a substantial increase from the 7.2 GW generated during a typical week. Concurrently, coal generation escalated from 9.2 GW to 13.2 GW, while net imports surged by 5.8 GW to accommodate the escalating demand dynamics.

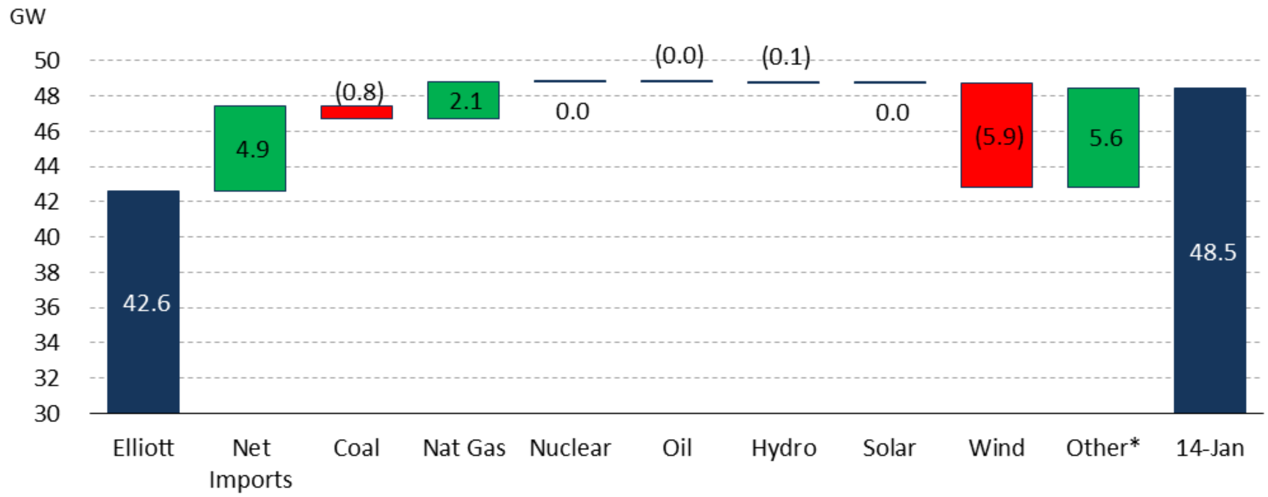
EXHIBIT 12: SPP - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR



Source: EIA Hourly Grid Monitor; *"Other" includes unaccounted generation to meet demand

The subsequent two exhibits compare the January 2024 winter storm with preceding weather events, examining the shifts in generation patterns therein. Notably, the January 2024 storm surpassed Storm Elliott, with demand exceeding the latter by 6 GW, as shown in **EXHIBIT 13**. Concurrently, wind generation witnessed a reduction of nearly 6 GW during this period. To offset the shortfall, imports surged by almost 5 GW. In comparison, natural gas generation saw an additional output of 2.1 GW compared to its generation during Storm Elliott, facilitating the fulfillment of the escalating demand.

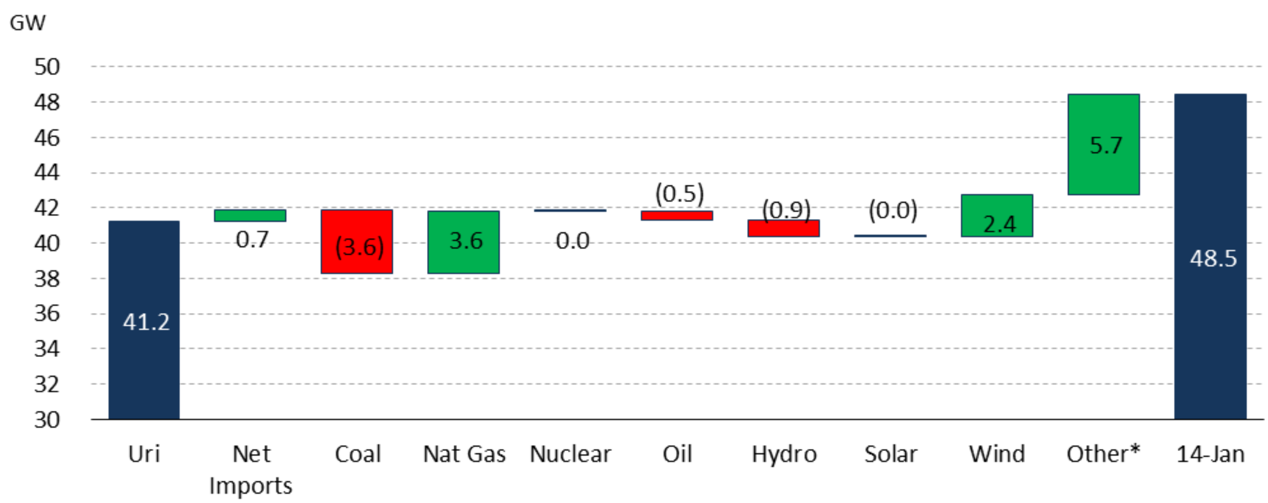
EXHIBIT 13: SPP - ELIIOTT'22 DEMAND VS. PEAK JANUARY'24 DEMAND



Source: EIA Hourly Grid Monitor; *"Other" includes unaccounted generation to meet demand

Compared to Winter Storm Uri, SPP experienced a reduction in coal generation by 3.6 GW during the peak of the January'24 storm, as shown in **EXHIBIT 14**. However, natural gas and wind generation witnessed notable increases to address the heightened demand associated with the January 2024 winter storm. Natural gas generation surged by 3.6 GW, while wind generation saw a commendable uptick of 2.4 GW, collectively contributing to meeting the needs of the prevailing weather event.

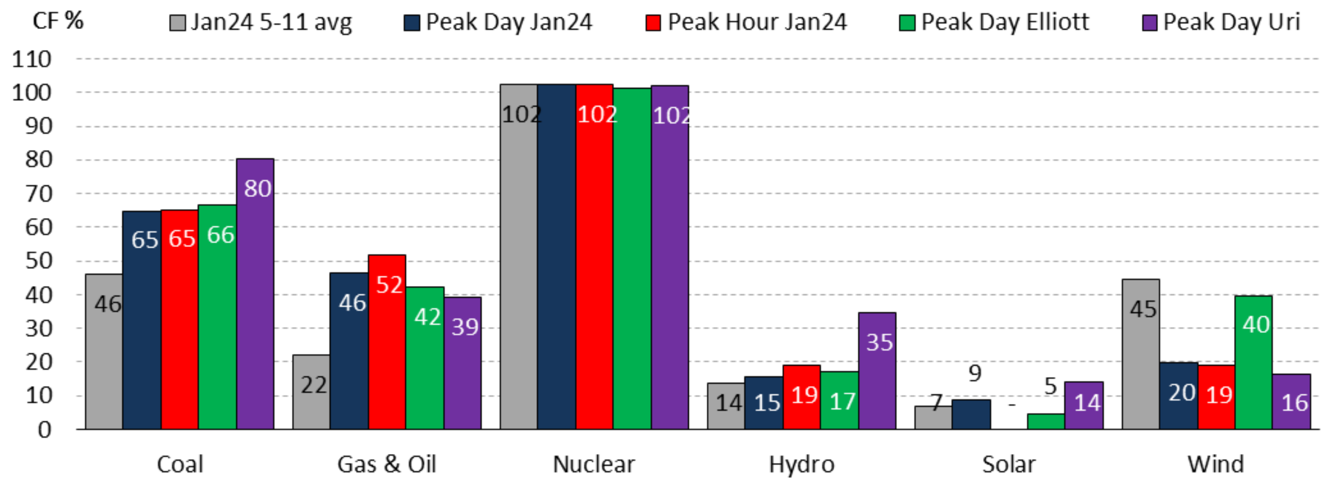
EXHIBIT 14: SPP - URI'21 DEMAND VS. PEAK JANUARY'24 DEMAND



Source: EIA Hourly Grid Monitor; *"Other" includes unaccounted generation to meet demand

EXHIBIT *15* shows the capacity factors of the different types of generating resources during various periods of peak demand compared to the second week of January 2024 in SPP. Coal and natural gas-fired generators significantly increased their utilization to meet the increased electricity demand during the height of the storm. **EXHIBIT *15*** shows the variability of wind and solar resources during these extreme weather events. Solar resources averaged less than a 10% capacity factor during the peak electricity demand day as the overall reduced solar radiation during the winter months and snow negatively impacted electricity output. Wind resources averaged a roughly 45% capacity factor during the second week of January. However, during the peak of the storm in SPP, wind capacity factors dropped to just 20%. Notably, during Elliott, SPP wind generators averaged a 40% capacity factor, reinforcing the extreme variability renewable generating resources can display during these extreme weather events.

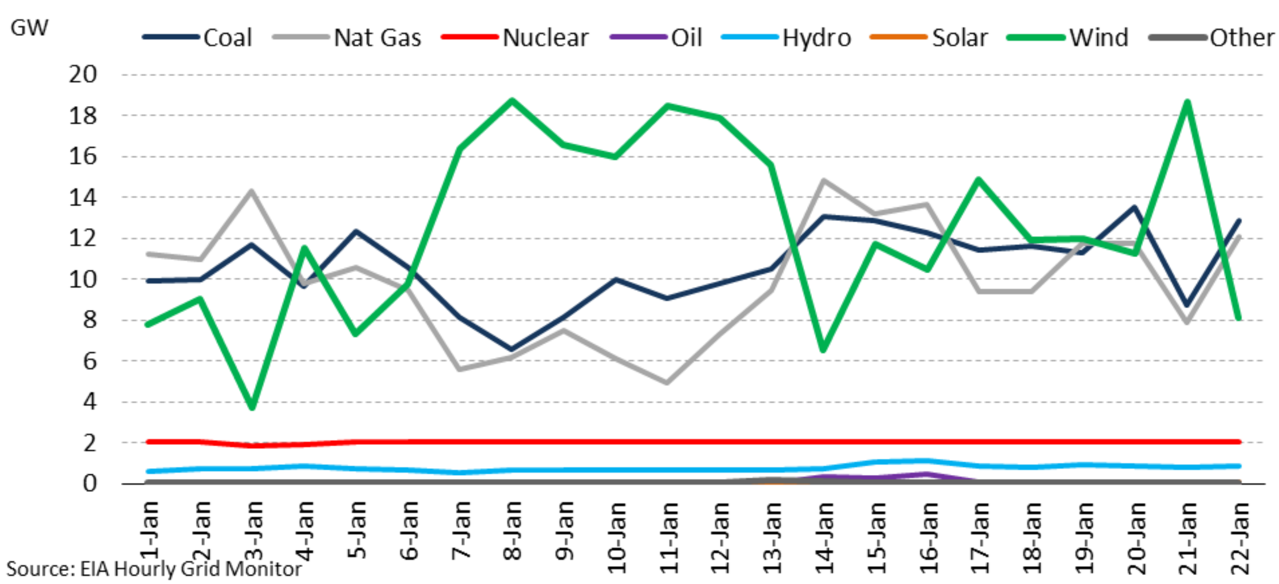
EXHIBIT 15: SPP - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



Source: EIA Hourly Grid Monitor & EIA 860 data

EXHIBIT 16 below shows SPP's average hourly generation profile throughout January 2024. While wind resources hold a significant share in overall generation, it is important to acknowledge the variability inherent in wind generation. Throughout January, wind generation exhibited considerable fluctuation, ranging from less than 4 GW to nearly 18 GW. Challenges arise when demand escalates during extreme weather conditions, placing strain on primary fuel sources. On January 14th, 2024, when demand peaked within SPP, wind generation experienced a notable decline, necessitating the escalation of coal and natural gas generation to fulfill the heightened demand.

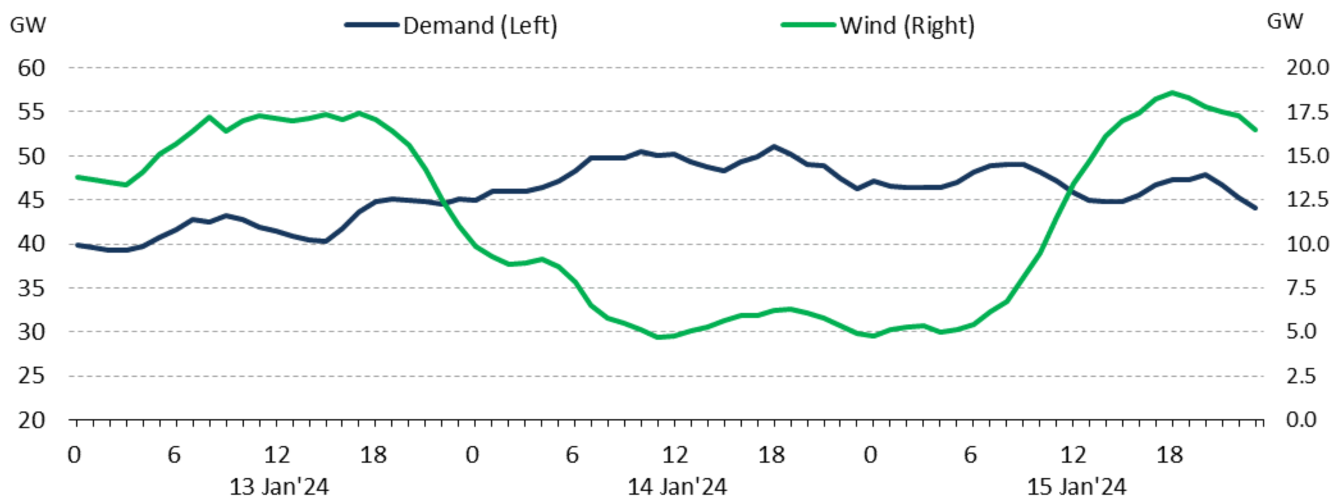
EXHIBIT 16: SPP - AVERAGE DAILY GENERATION BY FUEL TYPE - JANUARY 2024



Source: EIA Hourly Grid Monitor

Despite wind's substantial contribution to the generation portfolio within SPP, its capacity to complement demand requirements weakened during the January 2024 winter storm. As depicted in **EXHIBIT 17**, which describes the hourly demand trends observed during this period, a visible disparity emerges between escalating demand and wind generation capabilities. Notably, while demand exhibited a persistent upward trajectory commencing on January 14th, wind generation weakened, exhibiting a predominantly declining trend throughout the day.

EXHIBIT 17: SPP - HOURLY DEMAND VS. WIND GENERATION



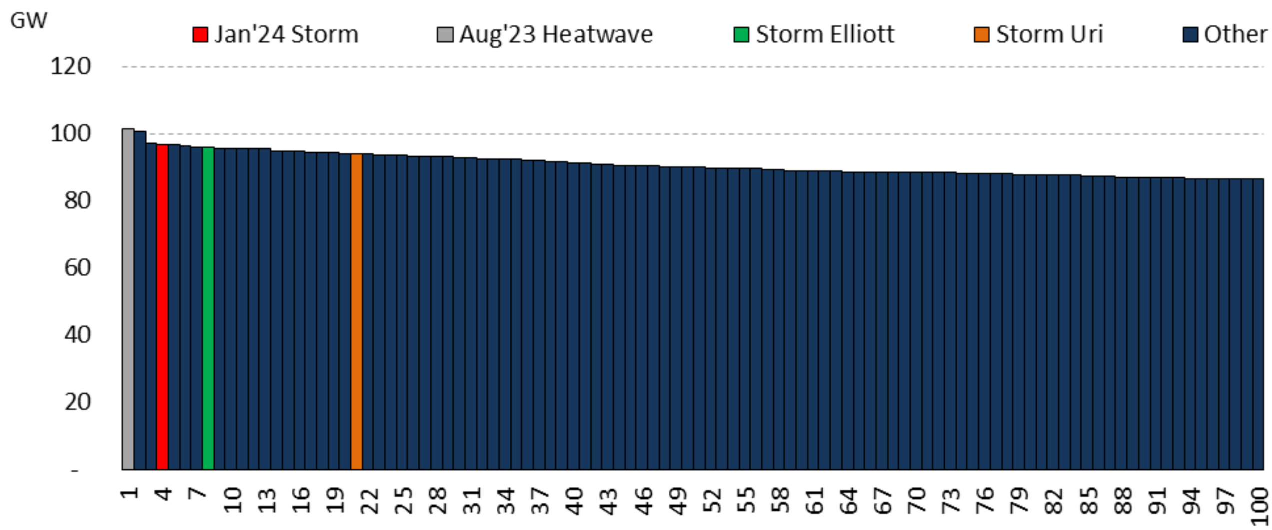
Source: EIA Hourly Grid Monitor

MISO

MISO (Midcontinent Independent System Operator) is the second-largest ISO in the U.S., managing the flow of electricity across 15 U.S. states and for over 45 million customers.

In a typical winter week, the MISO region experiences an average hourly demand of approximately 75 GW. The most notable peak demand occurred during the August 2023 heatwave, registering at 101 GW, as shown in **EXHIBIT 18**. The January 2024 winter storm closely followed with a demand of 97 GW, demonstrating its proximity to the highest historical demand. Storm Elliott and Storm Uri recorded demand levels of 96 GW and 94 GW, respectively, underscoring their comparable impact on the regional energy demand landscape.

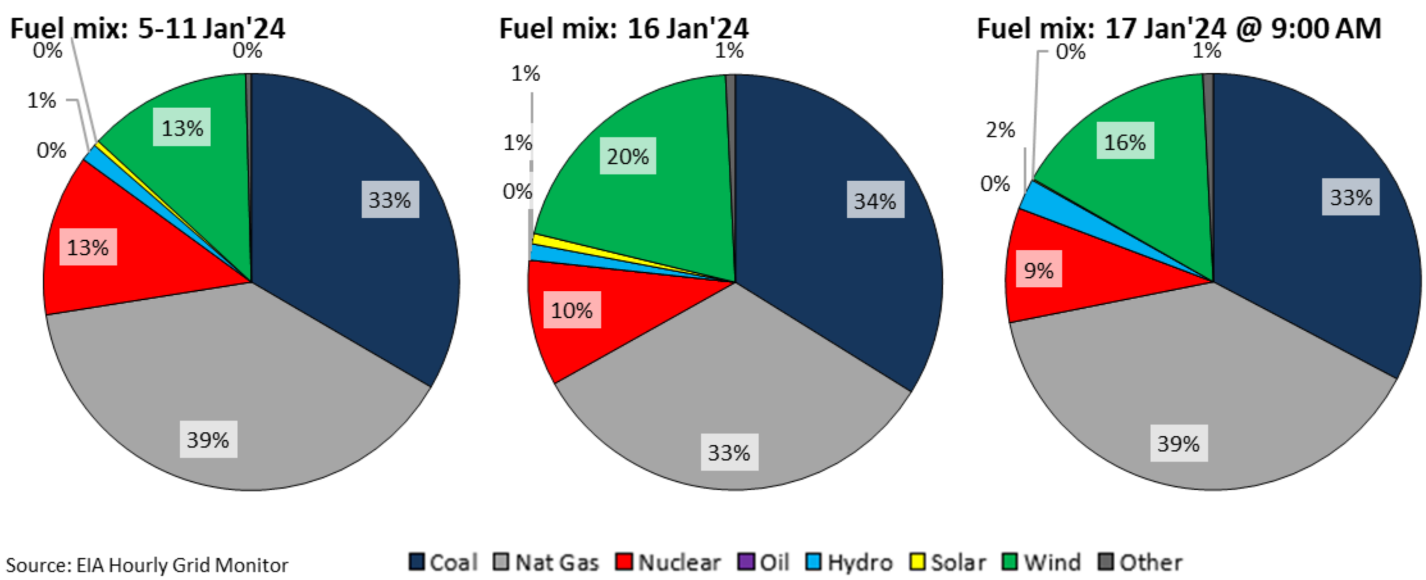
EXHIBIT 18: MISO - TOP 100 ELECTRICITY DEMAND DAYS



Source: EIA Hourly Grid Monitor

EXHIBIT 19, provided below, outlines the generation mix of MISO across three distinct periods. The initial chart illustrates MISO's generation mix during a typical week of average weather conditions, while the subsequent two charts depict the fuel mix during the peak day and peak hour of the January 2024 storm. On the peak demand day of the January 2024 storm, observed on the 16th, fossil fuels exhibited a relatively consistent fuel mix. However, wind resources experienced a substantial increase to accommodate the escalating demand. Wind generation more than doubled from 9.6 GW to 20 GW during this peak demand day. Similarly, during the peak demand hour at 9:00 AM on January 17th, wind resources demonstrated robust performance while fossil fuels provided essential backup support.

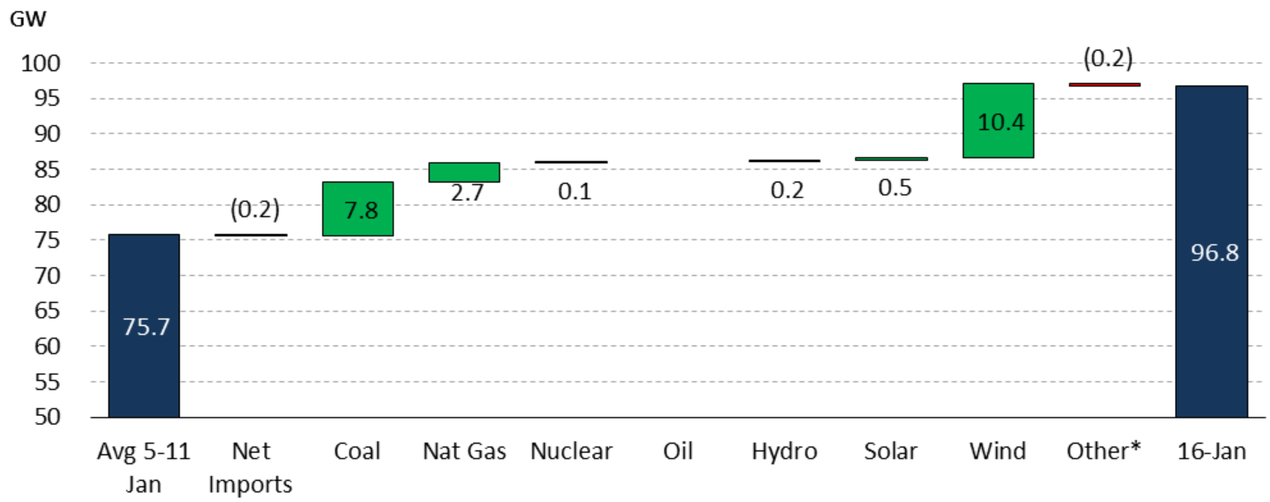
EXHIBIT 19: MISO - GENERATION MIX



Source: EIA Hourly Grid Monitor

EXHIBIT 20 compares the generation profiles between a typical weather week and the peak demand day of the January 2024 storm. Notably, there was a marked difference of over 20 GW in demand between these two periods. During the peak day, fossil fuel-based power plants significantly increased their generation output by over 10 GW to address the heightened demand. Concurrently, wind resources played a pivotal role in meeting the increased demand by generating an additional 10 GW, effectively contributing to the fulfillment of energy requirements during this critical period.

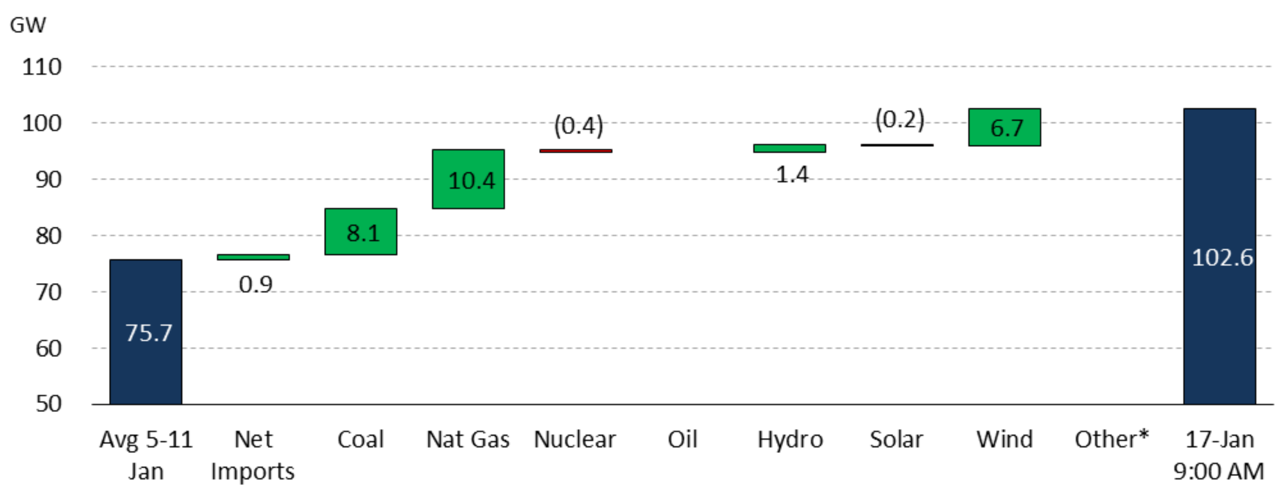
EXHIBIT 20: MISO - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY



Source: EIA Hourly Grid Monitor; *"Other" includes unaccounted generation to meet demand

Like **EXHIBIT 20**, **EXHIBIT 21** compares the generation mix between a standard demand week and the peak hour of the highest demand experienced during the January 2024 winter storm. Marking a record demand of 102 GW, this hour stands out as one of the most demanding within the MISO region's history. In response to this unparalleled demand, both fossil fuel-powered plants and wind resources underwent substantial escalation in generation to accommodate the escalating energy requirements.

EXHIBIT 21: MISO - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR

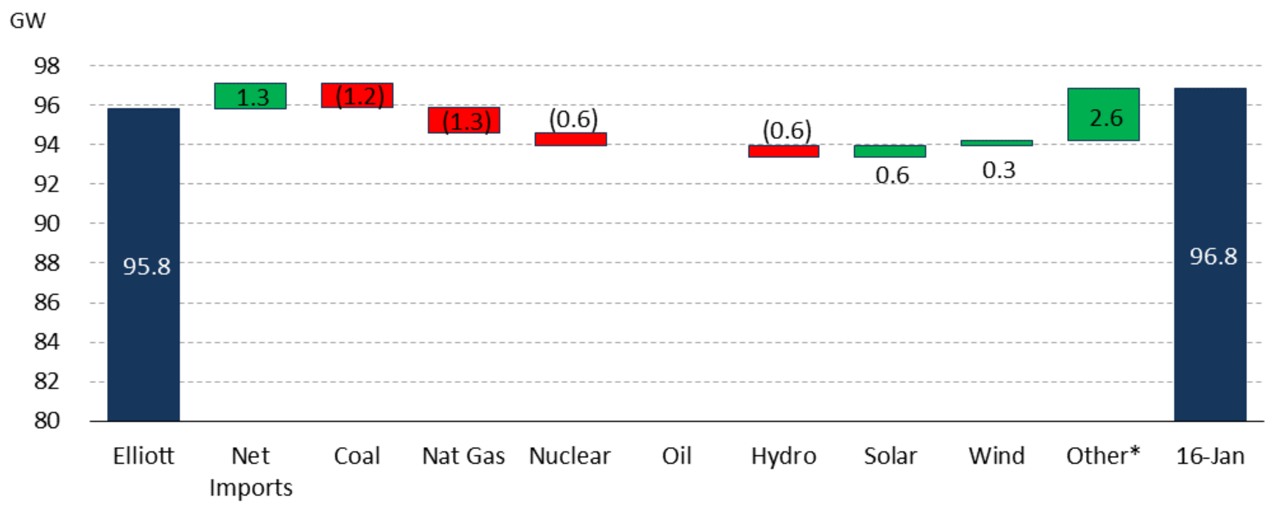


Source: EIA Hourly Grid Monitor; *"Other" includes unaccounted generation to meet demand

Despite the comparable magnitude of power demand witnessed during these events, a visible difference emerges in the generation mix. On the peak day of the January 2024 winter storm, there was a collective decrease in generation from coal and gas, amounting to 2.5 GW. Moreover, nuclear and hydropower sources fell short of producing nearly a gigawatt of electricity. In contrast, imports, coupled with solar and wind, collectively contributed over 2 GW of additional generation capacity.

EXHIBIT 22 compares the fuel mix during two significant weather events: Storm Elliott and the January 2024 winter storm. Despite the comparable magnitude of power demand witnessed during these events, a visible difference emerges in the generation mix. On the peak day of the January 2024 winter storm, there was a collective decrease in generation from coal and gas, amounting to 2.5 GW. Moreover, nuclear and hydropower sources fell short of producing nearly a gigawatt of electricity. In contrast, imports, coupled with solar and wind, collectively contributed over 2 GW of additional generation capacity.

EXHIBIT 22: MISO - ELLIOTT'22 DEMAND VS. PEAK JANUARY'24 DEMAND

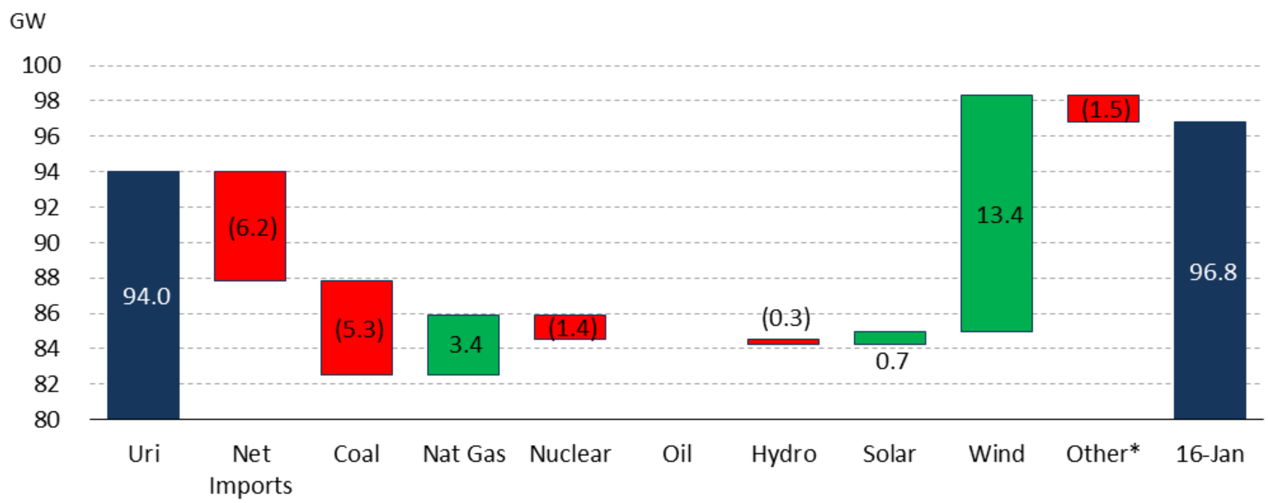


Source: EIA Hourly Grid Monitor, *"Other" includes unaccounted generation to meet demand

EXHIBIT 23 analyzes the fuel mix variance observed during another significant weather event, Storm Uri. Like Storm Elliott, Storm Uri demonstrated a stable demand pattern, with demand trailing just 2 GW behind that of the January 2024 winter storm.

However, the notable aspect lies in the divergence of the fuel mix. While imports experienced a decline of 6 GW and coal generation saw a reduction of 5.3 GW during the January 2024 storm compared to Storm Uri's fuel mix, wind generation demonstrated a remarkable increase of 13.4 GW compared to Storm Uri's recorded 6.6 GW. This observation holds particular interest, considering that during Storm Uri, the wind capacity in MISO stood at 26.3 GW. In contrast, during the January 2024 storm, it reached 30.6 GW, indicating a capacity addition of approximately 4 GW and yet a generation difference of 13.4 GW, implying that the remaining 8.4 GW of increased wind generation were due to higher wind speeds during the peak of the January 2024 storm. This underlines the most significant reliability issue with weather-dependent resources like wind.

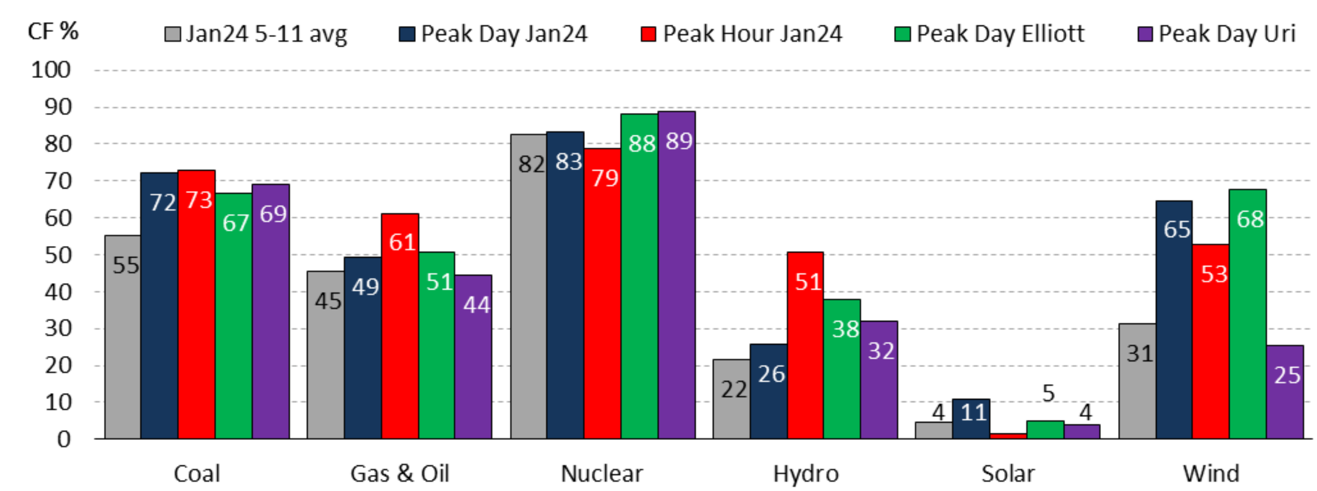
EXHIBIT 23: MISO - URI'21 DEMAND VS. PEAK JANUARY'24 DEMAND



Source: EIA Hourly Grid Monitor; *"Other" includes unaccounted generation to meet demand

Once again, **EXHIBIT *24*** shows the capacity factors of the different types of generating resources during various periods of peak demand compared to the second week of January 2024 in MISO. The biggest standout is the massive wind capacity factors during the latest storm and during Winter Storm Elliott, with capacity factors north of 60% during these storms. Conversely, the fleetwide average wind capacity factor during Winter Storm Uri was only 25%. While a small amount of variance can be explained by possibly increased availability of more wind turbines, the primary driver of the difference is the sustained higher wind speeds that accompanied the peak electricity demand periods during the last two storms in MISO.

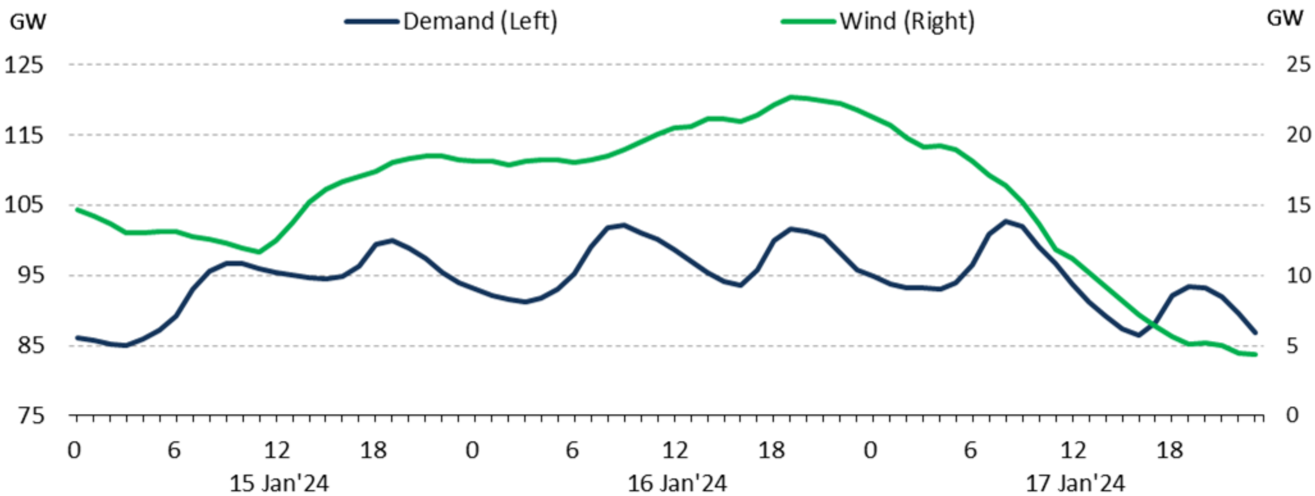
EXHIBIT 24: MISO - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



Source: EIA Hourly Grid Monitor & EIA 860 data

EXHIBIT 25 below offers a comprehensive overview of the hourly demand vs. wind generation trends observed during the January 2024 winter storm within the MISO region. Notably, wind resources played a pivotal role during the peak demand day of the January 2024 winter storm on January 16th, contributing 20 GW to the power delivery mix.

EXHIBIT 25: MISO - HOURLY DEMAND VS. WIND GENERATION



Source: EIA Hourly Grid Monitor

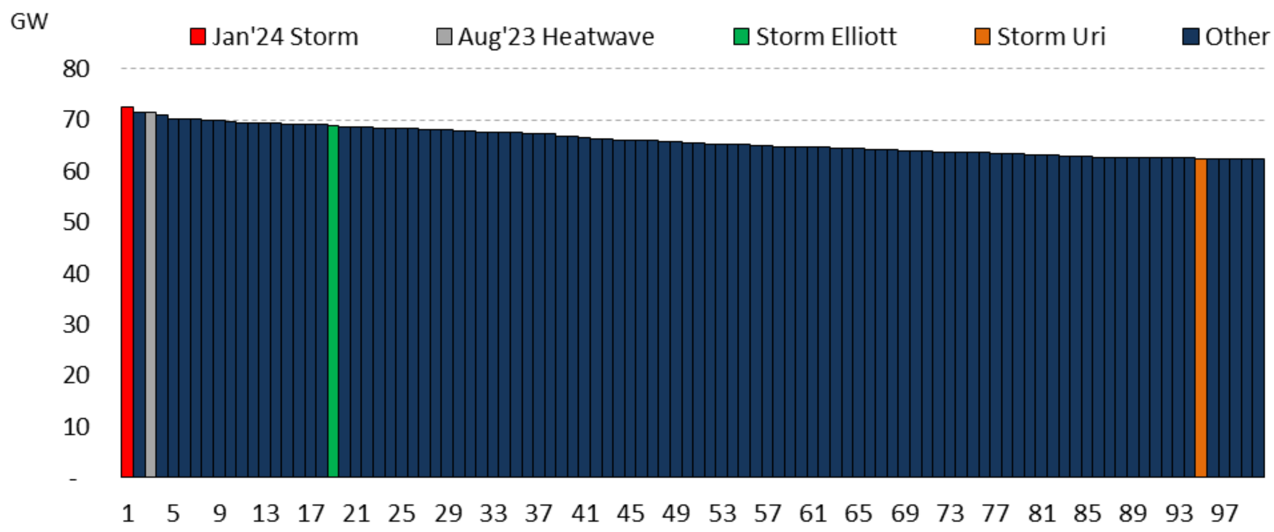
ERCOT

The Electric Reliability Council of Texas (ERCOT) operates as an independent system operator (ISO) confined solely within the borders of Texas. ERCOT's purview extends to managing the bulk electric power grid, serving over 26 million Texans, a demographic that encompasses approximately 90% of the state's electric load.

Under regular weather conditions, ERCOT typically runs with an hourly demand averaging around 50 GW. However, instances of peak demand have soared beyond 70 GW. The January 2024 winter storm caused one of the most formidable demand surges in ERCOT's history, peaking at 72.5 GW, overshadowing the demand witnessed during the August 2023 heatwave by a margin of 1 GW, as shown in **EXHIBIT 26**. Notably, Storm Elliott and Storm Uri registered demand peaks at 68.9 GW and 62 GW, respectively[8].

[8] Although forecasted peak demand for ERCOT during Winter Storm Uri surpassed 80 GW, actualized peak electricity demand was 62 GW as ERCOT disconnected various load centers (i.e., blackouts) to balance electricity demand with the available generation resources.

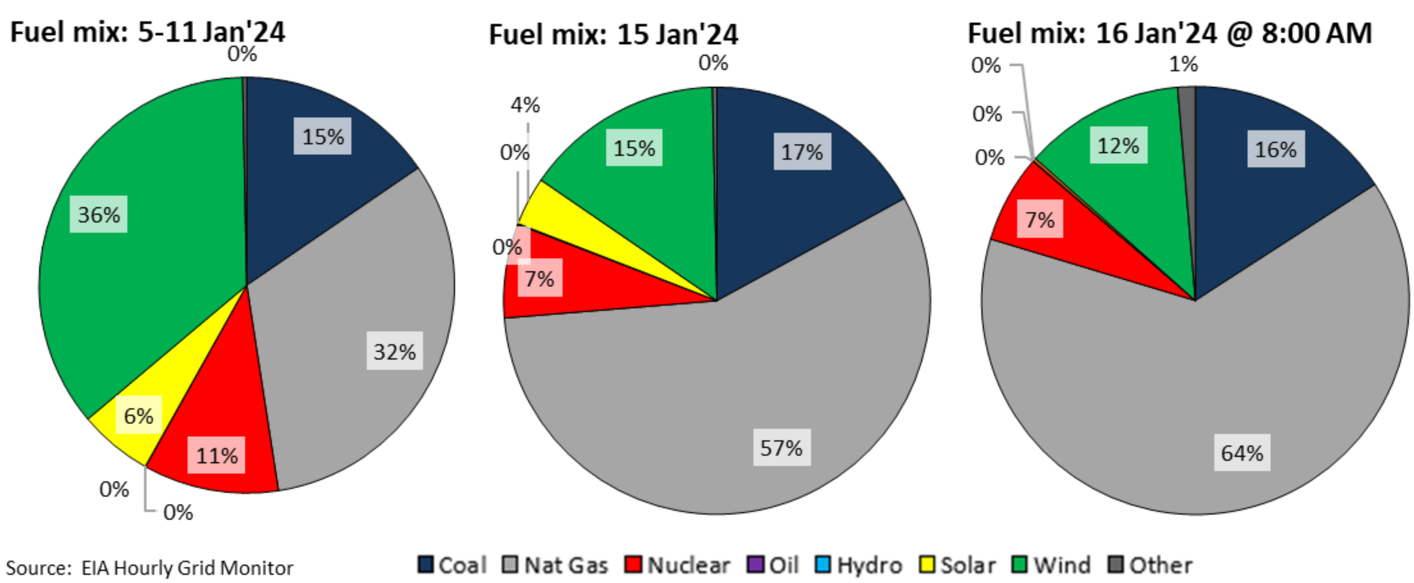
EXHIBIT 26: ERCOT - TOP 100 ELECTRICITY DEMAND DAYS



Source: EIA Hourly Grid Monitor

Within ERCOT, wind resources command a significant portion of the generation mix, followed by natural gas and coal, with solar and nuclear contributing to the remainder, as shown in **EXHIBIT 27**. Anticipating a peak in demand amidst the winter storm on January 16th, ERCOT diligently prepared its dispatch resources. However, during the peak day, wind generation's contribution to the generation mix dropped to 15%, a notable decrease from its regular weather conditions shares of 36%. Natural gas emerged as the primary workhorse, ramping up significantly to account for over half of the generation during the peak day. Likewise, coal generation experienced an uptick to align with the heightened demand. The peak demand hour at 8:00 AM precluded solar generation due to early morning conditions. Also, wind generation contributed only around 13% to the overall generation mix during the peak demand hour on January 16.

EXHIBIT 27: ERCOT - GENERATION MIX

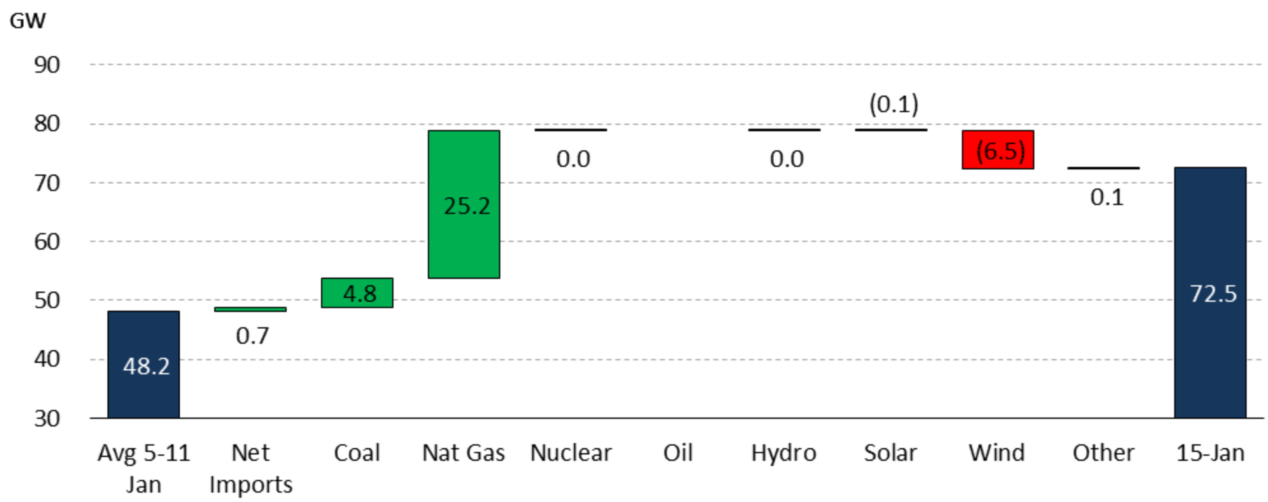


Source: EIA Hourly Grid Monitor

The subsequent two exhibits offer a comparative analysis of the demand and generation dynamics witnessed during the peak demand day and hour of the January 2024 storm, juxtaposed with the demand observed during a typical week in ERCOT.

Notably, the hourly demand surged by over 24 GW during the peak demand day in contrast to the hourly demand of a regular week, as shown in **EXHIBIT 28**. Natural gas emerged as the cornerstone in ensuring grid reliability, single-handedly augmenting its generation output from 15 GW to 40 GW. While wind generation experienced a decline of 6.5 GW, coal stepped up to the challenge by increasing its generation by nearly 5 GW, totaling 12 GW, thereby bridging the gap in demand effectively.

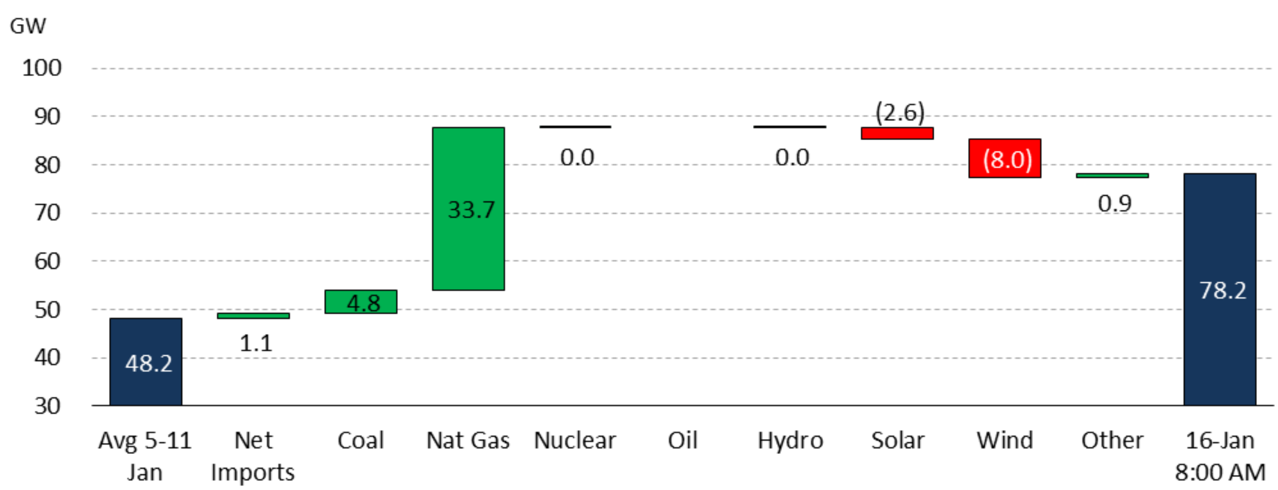
EXHIBIT 28: ERCOT - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY



Source: EIA Hourly Grid Monitor

The peak of demand during the January 2024 winter storm emerged during the nighttime hours, exceeding the average hourly demand of the peak day by 4 GW, as shown in **EXHIBIT 29**. Despite the absence of solar contribution due to the night-time, the onset of wind activity (21.6 GW), combined with the substantial ramping up of natural gas (37.2 GW) and coal resources (12 GW), facilitated ERCOT's ability to meet the demand surge during this critical peak hour.

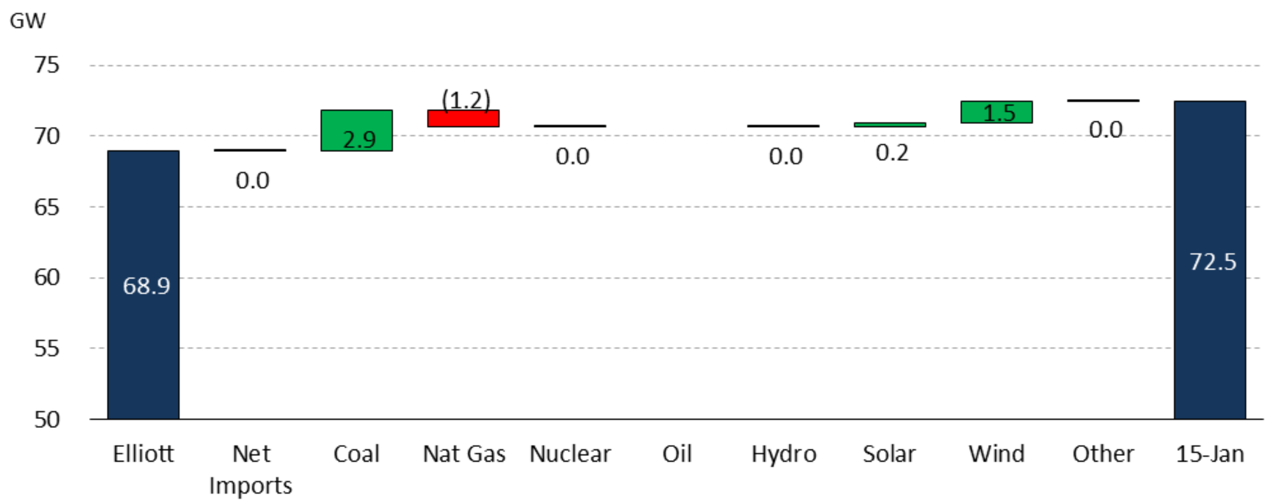
EXHIBIT 29: ERCOT - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR



Source: EIA Hourly Grid Monitor

EXHIBIT 30 compares the demand and generation patterns observed during Storm Elliott and the January 2024 winter storm. Notably, the demand during the January 2024 storm surged by 3.5 GW, primarily facilitated by heightened coal and wind generation, while natural gas experienced a marginal decline in its contribution.

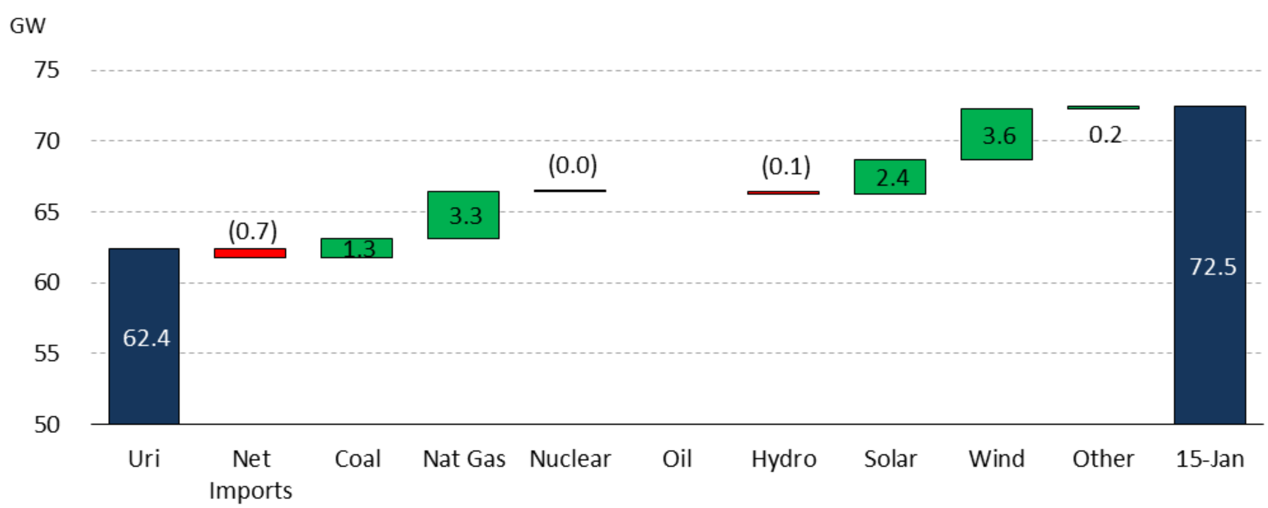
EXHIBIT 30: ERCOT - ELLIOTT'22 DEMAND VS. PEAK JANUARY'24 DEMAND



Source: EIA Hourly Grid Monitor

EXHIBIT 31 below compares the demand and generation dynamics between Storm Uri and the peak demand day of the January 2024 winter storm. Notably, the January 2024 storm exhibited a greater intensity, with demand soaring 10 GW higher than Storm Uri. This heightened demand was met through a balanced contribution from both fossil and renewable resources. Coal and gas collectively generated an additional 4.6 GW, while solar and wind resources combined to produce an additional 6 GW, effectively bridging the generation gap compared to Storm Uri.

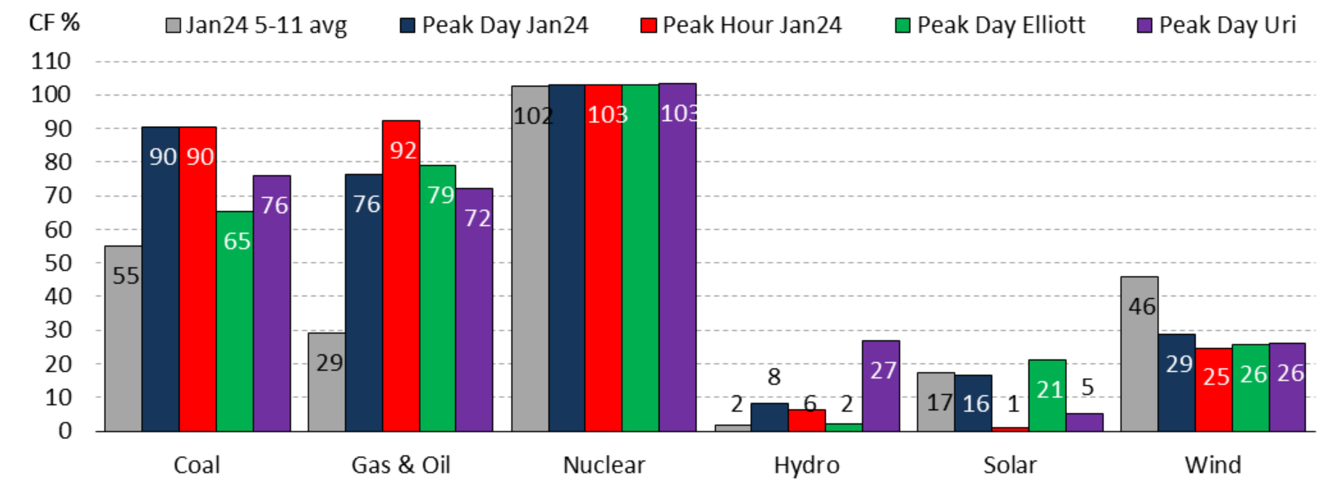
EXHIBIT 31: ERCOT - URI'21 DEMAND VS. PEAK JANUARY'24 DEMAND



Source: EIA Hourly Grid Monitor

Once again, **EXHIBIT 32** shows the capacity factors of the different types of generating resources during various periods of peak demand compared to the second week of January 2024 in ERCOT. During the January 2024 winter storm, ERCOT coal-fired power plants showed near-perfect availability and utilization, with capacity factors at or around 90%, which is massively improved from winter storms Elliott and Uri, when coal units averaged only 65% and 76% capacity factors, respectively. The ERCOT power grid was also massively helped by the high capacity factor of wind turbines during the peak demand hour during the latest storm, averaging 57%. Conversely, the daily average capacity factor of wind turbines of 29% is comparable to capacity factors achieved during winter storms Elliott and Uri.

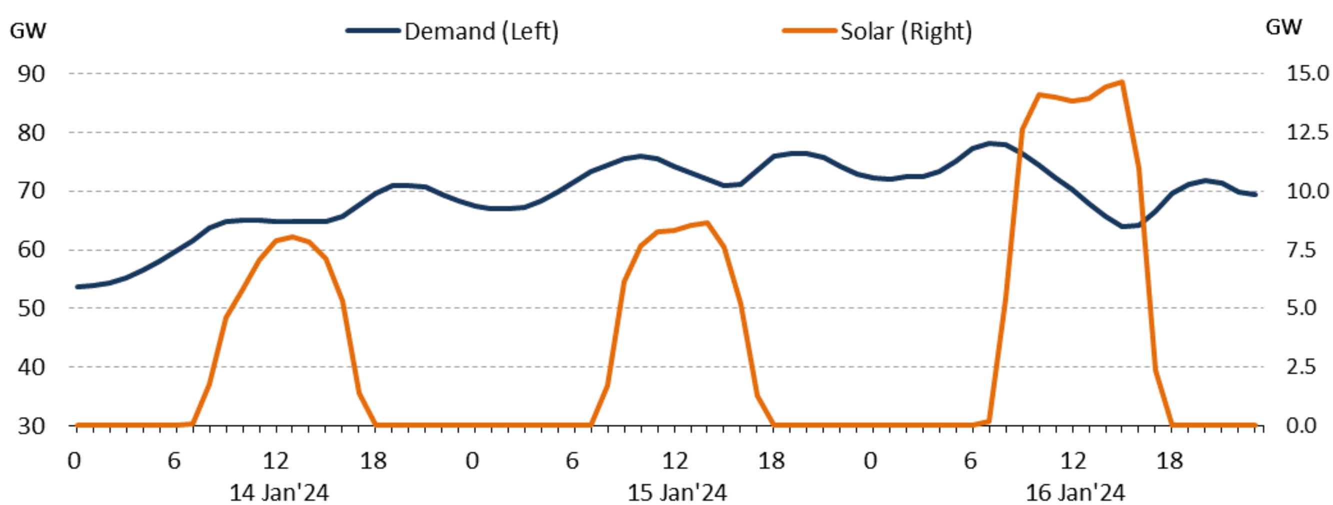
EXHIBIT 32: ERCOT - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



Source: EIA Hourly Grid Monitor & EIA 860 data

EXHIBIT 33 below presents the demand vs. solar generation patterns within ERCOT during the peak days of the January 2024 winter storm. Given the inherent characteristics of solar plants, this resource remained unavailable for most evening hours, coinciding with ERCOT's encounter with record-high demands.

EXHIBIT 33: ERCOT - HOURLY DEMAND VS. SOLAR GENERATION



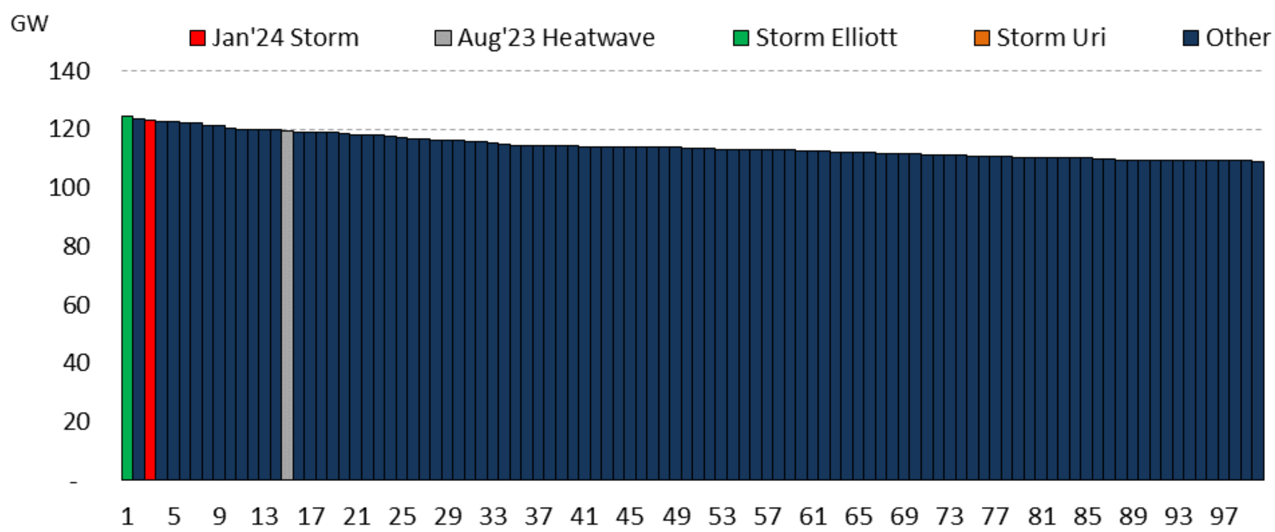
Source: EIA Hourly Grid Monitor

PJM

The PJM Interconnection, the largest Independent System Operator (ISO) in the nation by capacity, serves approximately 65 million customers across 13 states and the District of Columbia. Typically, PJM experiences an average hourly demand of approximately 95-98 GW during the winter, with the highest observed peak hourly demand reaching 124 GW during extreme weather events.

While Storm Elliott recorded the highest demand within the PJM region, the January 2024 winter storm closely followed, trailing by just 1 GW with an average hourly demand reaching 123.2 GW, as depicted in **EXHIBIT 34**. Furthermore, the demand profile during the August 2023 heatwave exhibited a similar intensity, sparking a demand of 120 GW within the PJM Interconnection.

EXHIBIT 34: PJM - TOP 100 ELECTRICITY DEMAND DAYS

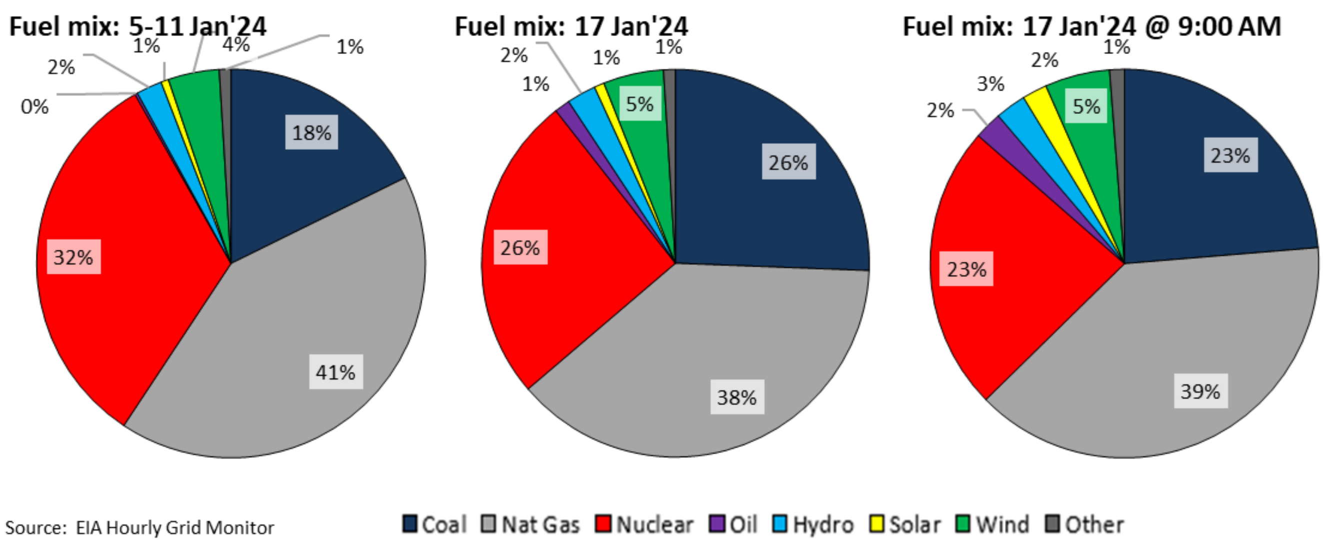


Source: EIA Hourly Grid Monitor

In PJM, nuclear power accounts for nearly one-third of the overall generation capacity. However, during the January 2024 winter storm, the rapid surge in demand led to a notable shift in the fuel mix, as depicted in **EXHIBIT 35**. Coal generation took precedence, experiencing a significant increase to comprise over 25% of the fuel mix. At the same time, natural gas generation also escalated to sustain a nearly consistent fuel mix compared to typical winter weather conditions.

During the peak hour of the winter storm, a concerted effort was observed across various fuel technologies, with most increasing their generation outputs to uphold the fuel mix equilibrium and meet the heightened demand effectively.

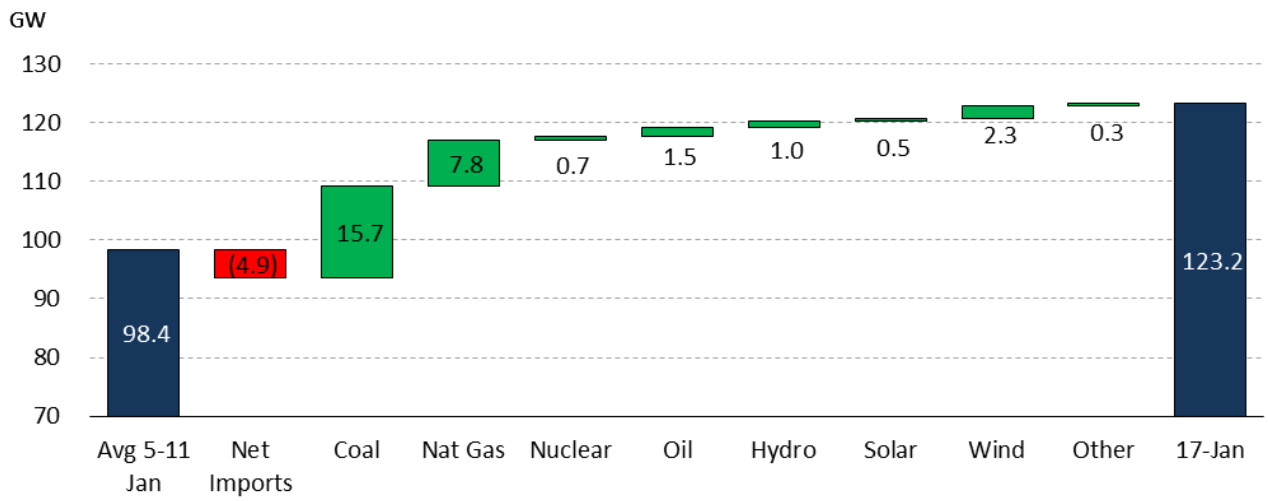
EXHIBIT 35: PJM - GENERATION MIX



Source: EIA Hourly Grid Monitor

EXHIBIT 36 compares the demand and average hourly generation across different fuel technologies between a typical winter week and the peak day of the January 2024 winter storm in PJM. Notably, a substantial demand disparity of 25 GW was observed between these two periods. Given the robust capacity of PJM, during this peak demand period, PJM demonstrated its resilience by exporting nearly 5 GW on an hourly basis to neighboring regions, thereby bolstering their reliability. In response to the heightened demand, fossil fuels witnessed an approximate 85% increase in generation, with coal and gas collectively generating 15.7 GW and 7.8 GW higher outputs, respectively, compared to the regular winter week. Additionally, wind and solar resources combined contributed an additional 2.8 GW to the overall demand-supply equation.

EXHIBIT 36: PJM - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY



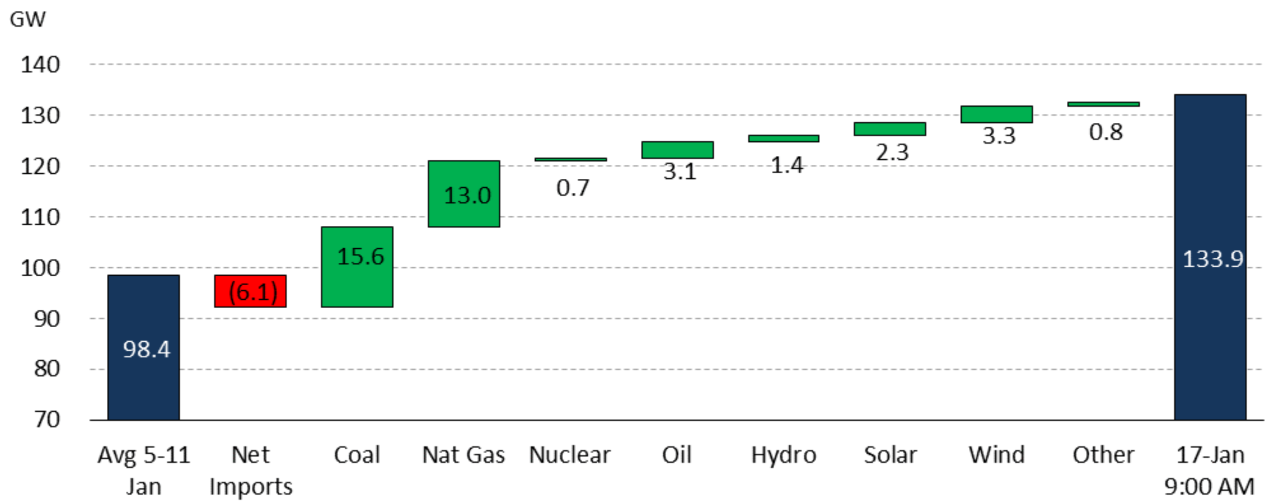
Source: EIA Hourly Grid Monitor

EXHIBIT 37, provided below, offers a detailed comparative examination of the average hourly generation across different fuel technologies between a typical winter week and the peak hour of the January 2024 winter storm within the PJM region. Notably, the peak hour demand surged to nearly 134 GW, prompting PJM to generate approximately 144 GW to meet this heightened demand and export surplus energy to neighboring regions.

During this critical hour, coal generation stood at approximately 34 GW, while natural gas escalated its production to bridge the demand gap by generating 13 GW higher compared to a typical winter week. Additionally, oil contributed 3

GW, whereas solar and wind resources combined accounted for a further increase of 5.5 GW compared to their generation levels during a regular winter week.

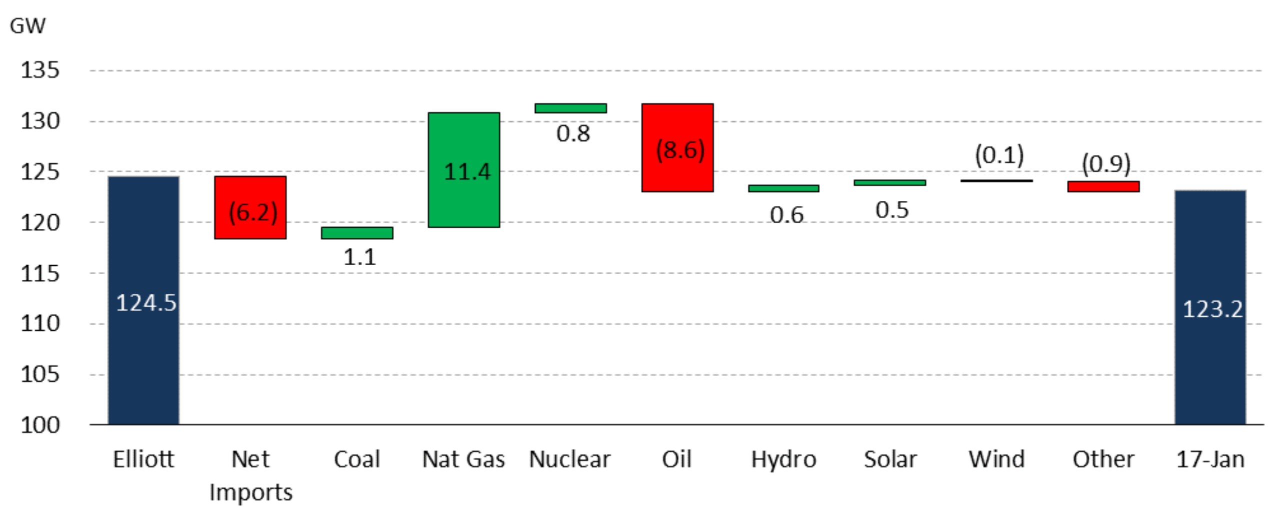
EXHIBIT 37: PJM - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR



Source: EIA Hourly Grid Monitor

EXHIBIT 38 provides a comparative analysis between Storm Elliott and the January 2024 winter storm. While the peak demand for both storms was nearly identical, PJM's approach to managing these situations differed significantly. During Storm Elliott, PJM exported approximately 6 GW less than the January 2024 storm. Moreover, natural gas generation during Storm Elliott was notably lower by 11.4 GW, primarily due to plant failures, which also impacted oil-based power generation. During Storm Elliott, oil accounted for 10.3 GW of generation, whereas during the January 2024 storm, it contributed merely 1.7 GW.

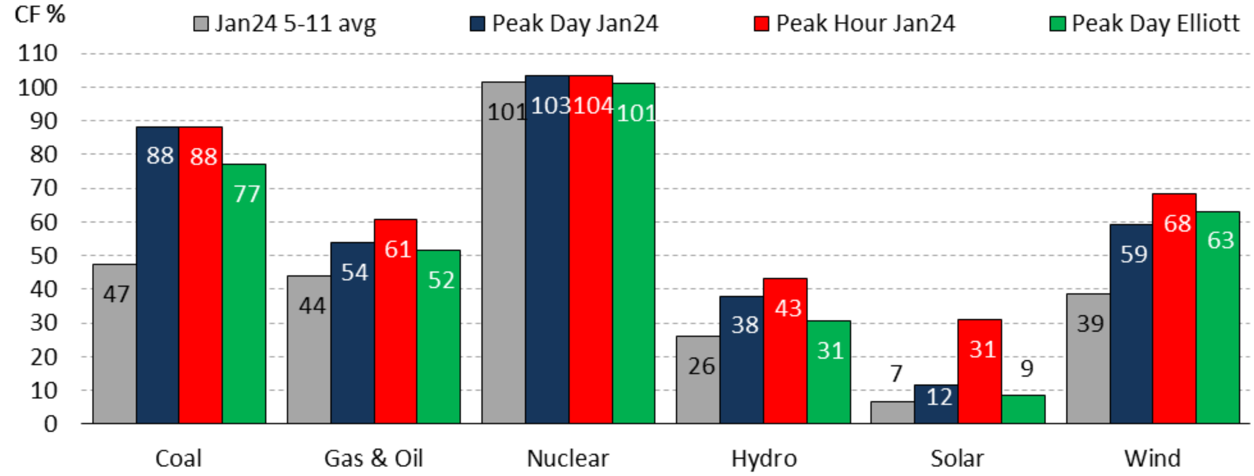
EXHIBIT 38: PJM - ELLIOTT'22 DEMAND VS. PEAK JANUARY'24 DEMAND



Source: EIA Hourly Grid Monitor

Once again, **EXHIBIT 39** shows the capacity factors of the different types of generating resources during various periods of peak demand compared to the second week of January 2024 in PJM. Similar to their brethren in ERCOT, capacity factors of PJM coal units increased massively to a near-perfect 88% during the peak demand day and hour of the January 2024 storm. Natural gas-fired power plants in PJM also showed increased utilization compared to the second week of January and Elliott. The increase in natural gas capacity in PJM between December 2022 and January 2024 allowed natural gas generation to increase while capacity factors remained comparable.

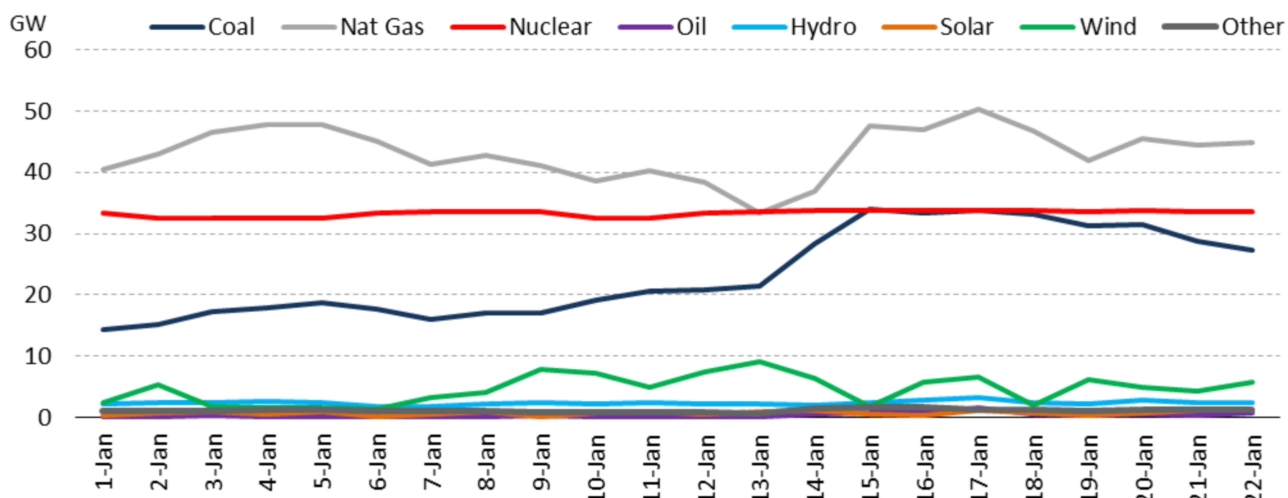
EXHIBIT 39: PJM - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



Source: EIA Hourly Grid Monitor & EIA 860 data

EXHIBIT 40 offers a comprehensive overview of hourly fuel generation throughout January 2024. Notably, during the peak days of the January 2024 storm (January 15th to 19th), there was a notable increase in natural gas and coal generation. Wind generation exhibited fluctuations throughout the entire month, while other fuel resources, apart from nuclear, did not make significant contributions.

EXHIBIT 40: PJM - AVERAGE DAILY GENERATION BY FUEL TYPE - JANUARY 2024



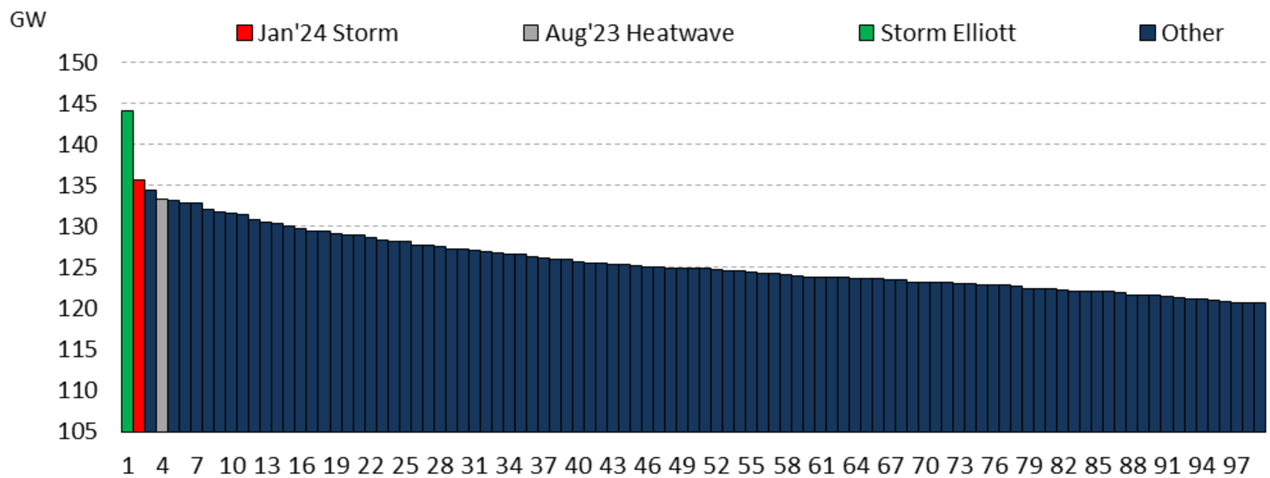
Source: EIA Hourly Grid Monitor

Southeast

The Southeast region includes most of the states of North & South Carolina, Georgia, Florida, Alabama, Tennessee, Kentucky, and Mississippi and its major utilities, including Duke Energy, Southern Company, Dominion South Carolina, Florida Power & Light, and Tennessee Valley Authority (TVA).

The Southeast region typically sustains an average demand of 100 GW. However, extreme weather events have led to a surge of nearly 50% beyond this norm. Notably, Storm Elliott stands as the top demand occurrence within the Southeast region, with demand peaking at 144 GW, as shown in **EXHIBIT 41**. Following closely, the January 2024 winter storm ranks second, commanding a demand of 136 GW. The August 2023 heatwave trails in fourth place, with demand reaching 133 GW.

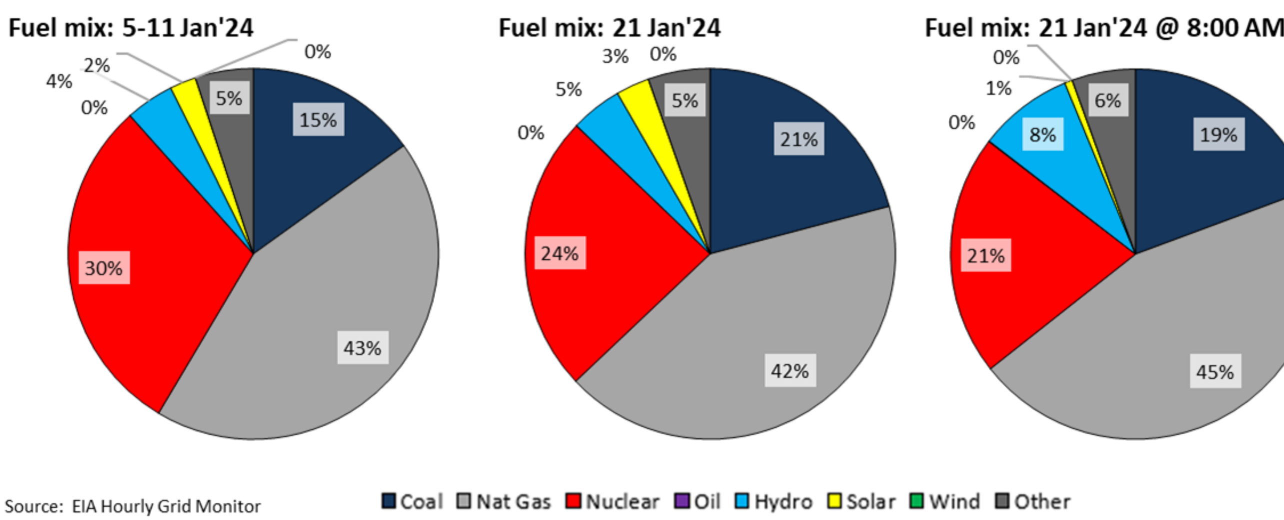
EXHIBIT 41: SOUTHEAST - TOP 100 ELECTRICITY DEMAND DAYS



Source: EIA Hourly Grid Monitor

The Southeast region relies on natural gas and nuclear as its primary generation resources. During the storm, the generation mix share of nuclear decreased as power generation remained consistent. However, shares for natural gas remained similar, and that of coal increased, indicating a ramp-up in generation from regular winter weather conditions from 5th -11th January 2024, as shown in **EXHIBIT 42**.

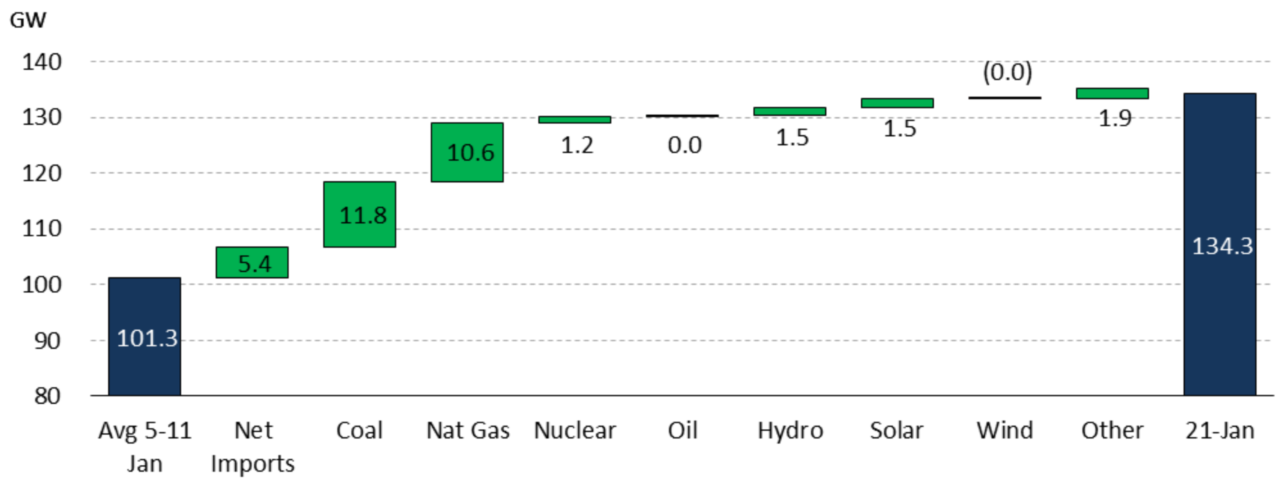
EXHIBIT 42: SOUTHEAST - GENERATION MIX



Source: EIA Hourly Grid Monitor

As the hourly demand escalated from 101.3 GW to 134.3 GW between the periods of January 5th-11th and January 21st amid the storm, coal generation bridged an additional deficit of 11.8 GW, while natural gas bolstered supply by an additional 10.6 GW compared to a typical winter week as shown in **EXHIBIT 43**. Notably, net imports also contributed to the heightened generation, accounting for an additional 5.4 GW.

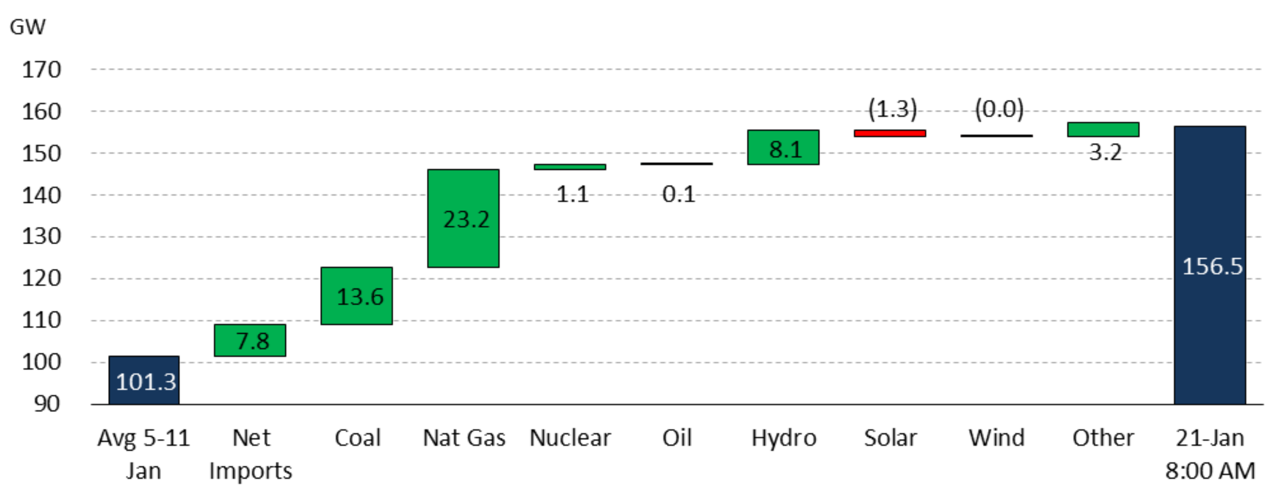
EXHIBIT 43: SOUTHEAST - AVG. OPERATIONS VS. DURING PEAK DEMAND DAY



Source: EIA Hourly Grid Monitor

During the peak demand hour, demand surged to approximately 157 GW, contrasting sharply with the average demand of around 100 GW, as shown in **EXHIBIT 44**. To address this deficit, natural gas played a pivotal role by contributing an additional 23.2 GW, culminating in a total generation of 68 GW. Following closely, coal augmented its generation by 13.6 GW, yielding a total generation of 29 GW. Concurrently with these increases, imports surged by nearly 8 GW. Concurrently, hydropower emerged as a significant contributor, generating an additional 8 GW to address the unprecedented demand peak effectively.

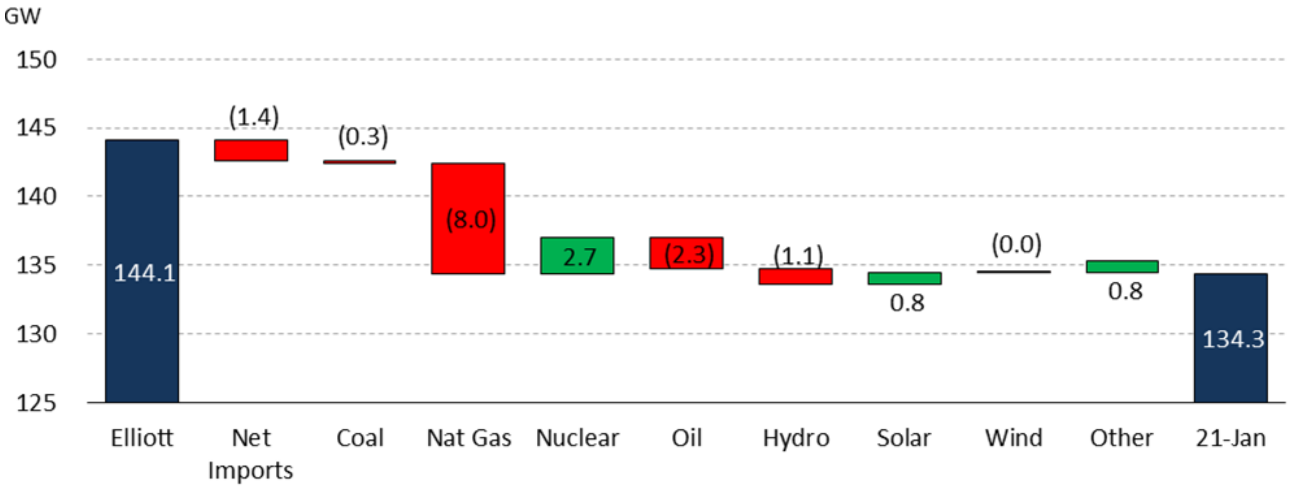
EXHIBIT 44: SOUTHEAST - AVG. OPERATIONS VS. DURING PEAK DEMAND HOUR



Source: EIA Hourly Grid Monitor

The demand observed during Winter Storm Elliott exceeded that of the January 2024 winter storm by nearly 10 GW. Natural gas emerged as the primary contributing generation source in both winter storms, exhibiting a discernible increase in generation to align with the heightened demand. During the January 2024 winter storm, nuclear generation recorded a notable increase of 2.7 GW compared to Winter Storm Elliott. Winter Storm Elliott relied on oil for generation, a component not utilized during the January 2024 Winter Storm. Consequently, this resulted in a reduction of 2.3 GW in oil generation in comparison to Winter Storm Elliott. Coal generation remained relatively consistent despite the variance in demand between the two winter storms.

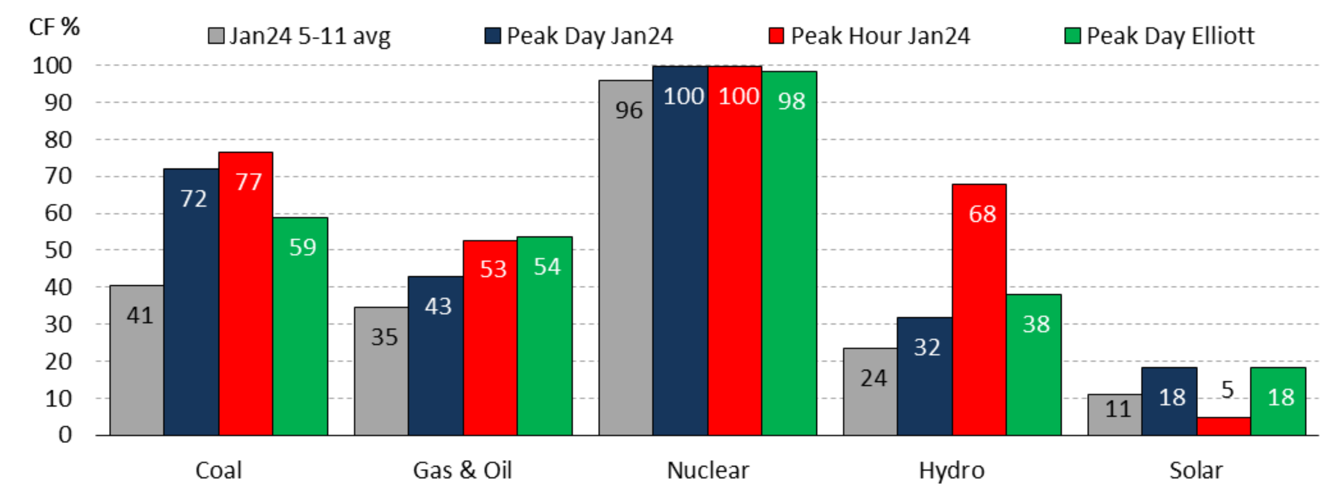
EXHIBIT 45: SOUTHEAST - ELLIOTT'22 DEMAND VS. PEAK JANUARY'24 DEMAND



Source: EIA Hourly Grid Monitor

Once again, **EXHIBIT *46*** shows the capacity factors of the different types of generating resources during various periods of peak demand compared to the second week of January 2024 in the Southeast. Coal-fired power plants once again showed the most significant increase in capacity factor during the peak of the January 2024 winter storm compared to the second week of January. Natural gas generators showed lower fleetwide capacity factors compared to Elliott due to the lower overall electricity demand during the latest storm, requiring less generation from all resources.

EXHIBIT 46: SOUTHEAST - CAPACITY FACTOR BY FUEL TYPE DURING PEAK DEMAND TIMES



Source: EIA Hourly Grid Monitor & EIA 860 data