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Quantitative assessment of U.S. bulk power systems and market operations during the COVID-19 pandemic

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A R T I C L E I N F O

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A B S T R A C T

Starting in early 2020, the novel coronavirus disease (COVID-19) severely attached the U.S., causing substantial changes in the operations of bulk power systems and electricity markets. In this paper, we develop a data-driven analysis to substantiate the pandemic's impacts from the perspectives of power system security, electric power generation, electric power demand and electricity prices. Our results suggest that both electric power demand and electricity prices have discernibly dropped during the COVID-19 pandemic. Geographically diverse impacts are observed and quantified, while the bulk power systems and markets in the northeast region are most severely affected. All the data sources, assessment criteria, and analysis codes reported in this paper are available on a GitHub repository.

1. Introduction

1.1. Background and motivation

The novel coronavirus disease (COVID-19) outbreak was declared a global pandemic by the World Health Organization (WHO) on March 11, 2020 [1]. Two days later, the U.S. federal government issued a national emergency proclamation [2]. A series of emergency measures, however, failed to stop the rapid spread of COVID-19, and the U.S. soon became a new epicenter of the global outbreak [3]. To slow the spread of COVID-19, all states have implemented various policy interventions [4], e.g., lockdown orders, social distancing measures, which directly caused an unprecedented reduction of commercial and industrial electricity consumption. While the society is still trying to adapt to the changes brought by COVID-19, it is becoming evident that this public health crisis has shown a greater impact than originally anticipated by most experts [5,6].

This paper pays special attention to the pandemic's impact on U.S. bulk power systems and wholesale electricity markets. According to an overview [7] from the Federal Energy Regulatory Commission (FERC), there are seven regional transmission organizations, or wholesale electricity markets, in the U.S.—California (CAISO), Midcontinent (MISO), New England (ISO-NE), New York (NYISO), Pennsylvania-New Jersey-Maryland Interconnection (PJM), Southwest Power Pool (SPP), and Texas (ERCOT).

Owing to the high quality and timely release, electricity market data are ideal for tracking the potential impacts of COVID-19. The existing marketplaces in the U.S. also largely cover most of the hotspot states. Fig. 1 shows the confirmed COVID-19 cases of July 20, 2020, at both the state level (heat map zones) [8] and the electricity marketplace level (shaded zones) [7]. Here, the seven hardest-hit states and many dark blue areas (over 40 thousand confirmed cases) are properly covered by the existing U.S. electricity markets. These observations motivate us to make full use of the available market data to investigate how the electricity markets and power systems are affected during the COVID-19 pandemic.

1.2. Related literature and analysis

In late March, several reports discussed some pandemic-related changes. Reference [9,10] provided early observations of different electricity markets, and reference [11] commented on the additional issues of reliability risk, reduced bill payments, and delayed investment activities.

The Electric Power Research Institute (EPRI) reported more comprehensive observations around the world [12]. The demand

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changes observed in Europe, the U.S., and China were classified based on restriction severity, and full details about New York state were given as well. The IEEE Power & Energy Society released a report [13] collecting worldwide experiences and practices to mitigate the pandemic's adverse effects. In particular, this report presented many evidences regarding the electricity consumption, peak demand, and generation mix. Reference [14] investigated the socioeconomic and technical problems faced by utility companies under different global scenarios, and the Indian power system was scrutinized as a case study.

The Energy Information Administration (EIA) released a short-term energy outlook [15] in the first quarter and pointed out the uncertain impact on electricity generation. This report also found continuously low wholesale prices. Increasing residential electricity consumption in the U.S. Pecan Street company [16] made further efforts to monitor 113 homes in Austin, Texas. Residential demand was high all day long, making the "duck curve" smoother than it has been over the past few years. Refrigerators appeared to work overtime, but electric vehicles were taking a long rest. Reference [17] analyzed the day-ahead load forecasting under strict social distancing restrictions, and the mobility data were found quite helpful in boosting prediction accuracy.

From mid April, COVID-19 impact reports, mainly on electricity consumption, are periodically released by independent system operators (ISOs). In [18], ERCOT applied a backcast model to estimate the load reduction and found weekly drops in energy use from 4~5% in late April and 3~4% in mid-May to approximately 1% after mid-June. Electricity consumption in Texas was also lower during the early morning hours. A similar methodology was implemented by ISO-NE [19], and they also found that the demand impact after mid-June was very limited. PJM reported that the peak impact in July was noticeably easing, which was possibly due to gradual reopening as well as increasing weather sensitivity [20]. Additionally, the NYISO forecasting team stated that the commercial load reduction was a leading driver of low electricity demand [21]. Approximately 16% of transmission outages planned by MISO were moved in the past few months, mainly because of the COVID-19 pandemic [22]. A CAISO report showed that power grid reliability was not affected by the stay-at-home order [23].

There are many recent works assessing the COVID-19 impacts from different perspectives. Reference [24] regarded the pandemic as a unique opportunity to analyze the perturbation on sustainability transitions. Reference [25] stated that shortages of photovoltaic modules, labor, and government purchases might heavily postpone solar installation. Reference [26] claimed that countries rich in renewable energy were expected to see rapid increases in their shares of clean energy. In [27], the authors estimated a 9.20% reduction in global electricity production in 2020, and they calculated the change in global emissions accordingly. Reduced generation of natural gas plants [28] and reduced green house gas emission [29] were also observed in Canada. To navigate the crisis, reference [30] established a policy framework, including the short-term immediate response, mid-term economic recovery, and long-term energy transition. Similarly, reference [31] warned that COVID-19 could have a deep and negative impact on long-term innovation in clean energy if policy responses failed to take effect. COVID-19 assistance to target the energy insecurity of the low-income population was recommended by [32]. Furthermore, the impact of containment measures were carefully assessed in Europe [33,34] and the U.S.[35], and the demand change of building level [36], state level [37] as well as country level [38] were also analyzed.

In summary, COVID-19-related studies are still unsatisfactory for the following reasons: 1) limited depth and scope of study. For example, many power system–related indices have not been investigated in great detail. 2) Lack of cross-regional comparison. Given the broad geographical impact of COVID-19, a comprehensive cross-regional study of U.S. bulk power systems and markets could offer many valuable insights for policy makers. 3) Difficulty of scientific reproduction. Limitations around open-access data and well-organized tools make the aforementioned study results difficult to reproduce or analyze.

This paper offers a comprehensive perspective to evaluate the impact of COVID-19 on the U.S. bulk power system and market operations. Building upon our recent work [39], we have substantially extended the results by further considering the impacts on power system security, electric power generation, and electricity prices. A series of novel criteria are developed in this paper along with extensive quantitative details, visualization results, and discussions. In addition, all the data and code used in this paper are available in a ready-to-use format and are publicly shared for scientific reproduction.

1.3. Open-access data source and code

An open-access data hub, COVID-EMDA^{+} (Coronavirus Disease and Electricity Market Data Aggregation) [40], was established to track the potential impacts of COVID-19 on U.S. electricity markets and power systems. This data hub, with released data and parser tools, is updated daily to capture the latest situation. Data imports with web links could avoid repetitive data refreshing and management processes. Note that all the data, parser tools, and analysis code are available on a GitHub repository [40,41].

To see more details, this data hub collects and harmonizes raw data from all existing U.S. electricity markets and combines them with other cross-domain data sources, e.g., public health data. Fig. 2 lists all the data sources that are integrated in the COVID-EMDA^{+} data hub. The

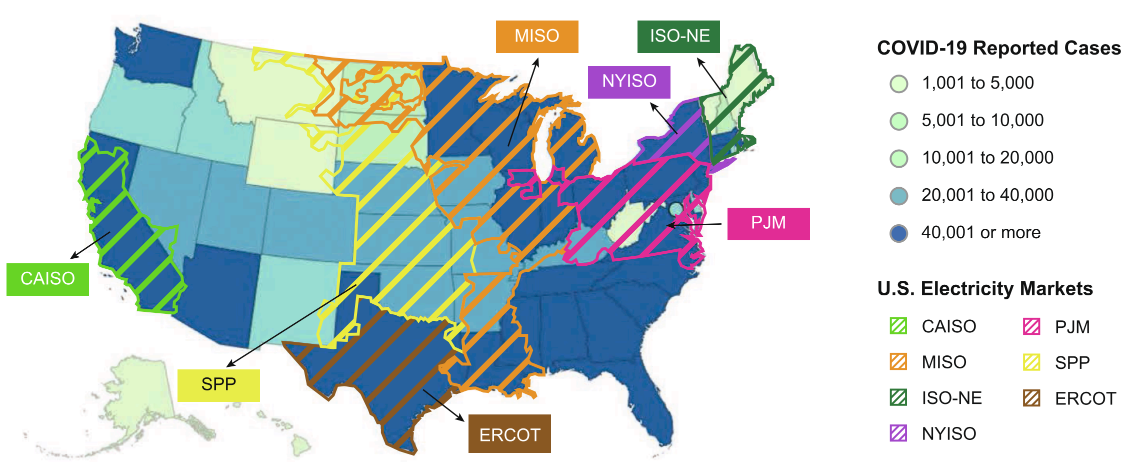

Fig. 1. U.S. confirmed COVID-19 cases of July 20, 2020. The seven electricity marketplaces cover the hardest-hit states, including New York, New Jersey, Illinois, California, Massachusetts, and Texas. Data source: U.S. Centers for Disease Control and Prevention (CDC) and Federal Energy Regulatory Commission (FERC).

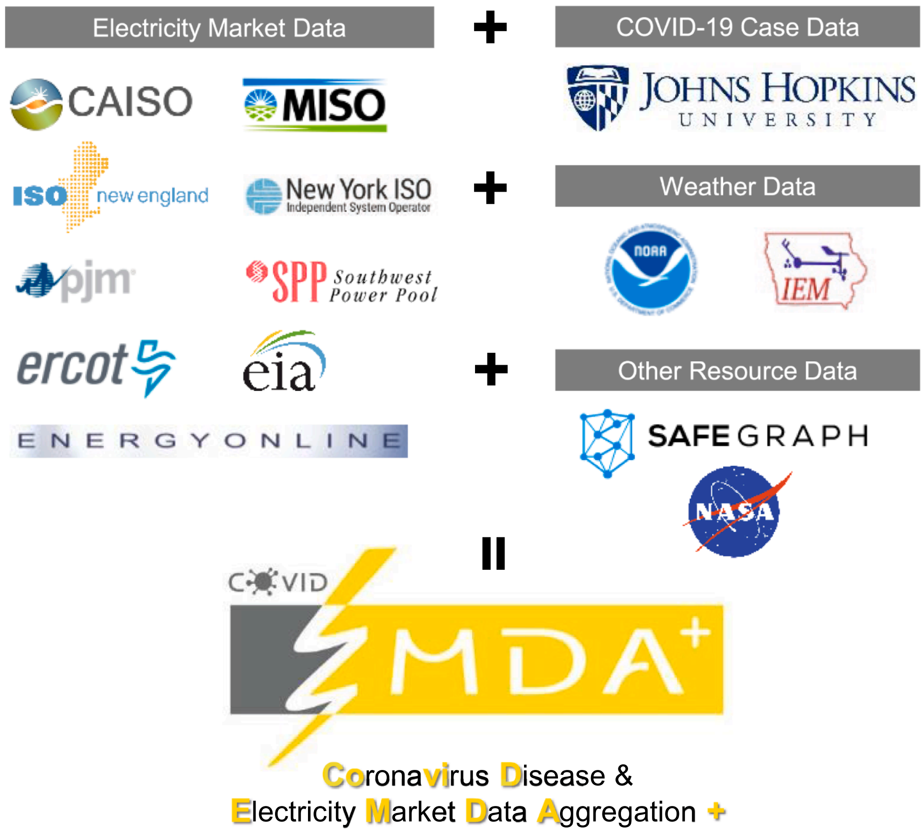

Fig. 2. Data source description of the COVID-EMDA+ data hub. This cross-domain data hub is designed to track the pandemic's impact on U.S. electricity markets and contributes to deepening a cross-domain understanding of the pandemic's impacts. All analysis results reported in this paper are based on this data hub, which is open access and updated daily on GitHub [40].

support team ensures data quality, handling most outliers and missing data by reviewing backup data sources or historical trends. Several dedicated strategies are designed to consider different data features.

1.4. Contributions and paper structure

We summarize the key contributions of this paper as follows.

1. This paper comprehensively assesses the impact of COVID-19 on the existing U.S. bulk power systems and markets. We conduct a data-driven analysis from the perspectives of power system security, electric power generation, electric power demand, and electricity prices. Many innovative criteria, e.g., excess change rates for renewables and abnormal price indices, are first developed in this paper.
2. We find significant impacts on electric power demand and electricity prices in most regions. The impact is validated to be relatively diversified, both in intensity and dynamics, while the northeast region is found to be more sensitive than other places. Additionally,

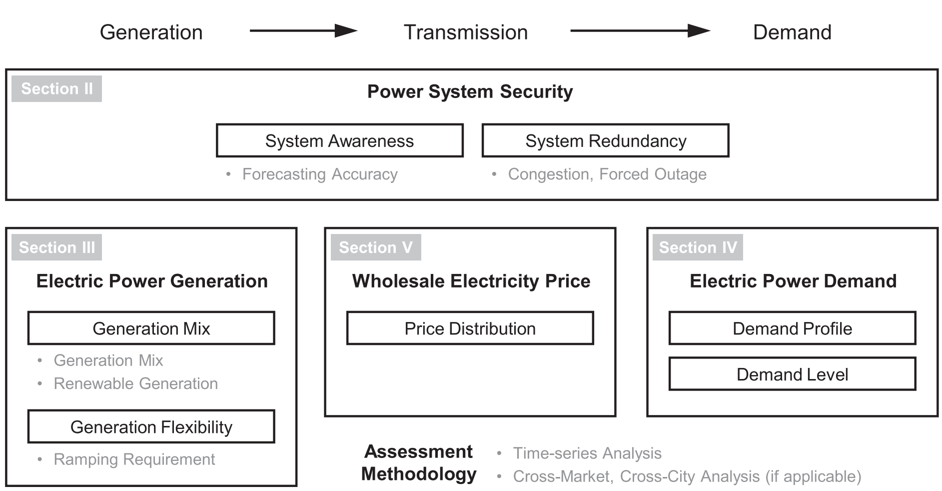

Fig. 3. Framework for the quantitative assessment. Four sections are designed to monitor the bulk power system and electricity markets from different perspectives. This paper applies time-series analysis and cross-market/city analysis to track the impact of COVID-19.

some evidences suggest that renewable generators are suffering extra curtailments due to COVID-19.

3. All the data sources and code used in this paper are publicly shared. With daily updates and rigorous quality control, these ready-to-use resources help support various pandemic-related studies.

Fig. 3 provides an overall framework of this paper, and four sections are designed to monitor the bulk power system and electricity markets from different perspectives: Section 2 – Section 5 are focused on the pandemic's impacts on power system security, electric power generation, electric power demand, and prices. Extensive results from different perspectives depict a full picture of the changes induced by COVID-19. Section 6 concludes this paper.

2. Impact on power system security

An electricity market is an economic system that balances the generation and demand in a power system. The first priority of market operators is monitoring the secure operation of the electric grid. This section analyzes how COVID-19 has affected the forecasting accuracy, congestion, and forced outages.

2.1. Forecasting accuracy

The pandemic has caused significant changes in electricity consumption patterns, so the demand forecasting may become less accurate. A poor prediction is likely to increase operation risks and waste more flexibility resources.

Here, we analyze day-ahead hourly demand forecasting and calculate the monthly mean absolute percentage errors, which are defined as follows.

$$e_{ym} = \frac{1}{N_m T}\sum_d \sum_t \left| \frac{\widehat{D}_{ymdt} - D_{ymdt}}{D_{ymdt}} \right|, \quad \forall y, m \tag{1}$$

where e_{ym} is the error for month m of year y, D_{ymdt} is the metered demand for year y, month m, day d, and hour t, and $\widehat{D}_{ymdt}$ is the day-ahead hourly forecast. In addition, N_m and T are the number of days and hours, respectively.

Using the above formula, Table 1 compares the forecasting errors in 2020 and 2019. There is a clear trend that the prediction errors are shrinking in most markets—larger errors occur before May, with accuracy improvements observed soon after. An interesting finding is that the prediction appears more accurate in July 2020 than in July 2019, implying a diminishing impact of COVID-19. Please note that the cross-market comparison is not applicable here because different market operators may use different prediction models.

Although the pandemic has posed new challenges for demand forecasting, the overall impact has been rather limited—even under the influence of COVID-19, the prediction errors are still within a tolerable range. Additionally, gradual improvement indicates that pandemic-induced risks have been properly managed with adequate data and knowledge accumulation.

Table 1
Demand forecasting error in U.S. electricity markets [%].

Market	March	April	May	June	July
CAISO	3.4 (**2.7**)	3.9 (**2.8**)	6.0 (**2.7**)	4.3 (**4.1**)	3.9 (**3.1**)
MISO	2.9 (**1.6**)	3.0 (**1.3**)	1.7 (**1.3**)	2.4 (**1.8**)	1.7 (**1.6**)
ISO-NE	2.5 (**2.3**)	2.7 (**2.5**)	3.1 (**2.4**)	2.5 (**2.4**)	**2.1** (3.1)
NYISO	**2.3** (2.8)	**2.7** (3.1)	**2.0** (3.2)	**2.4** (3.1)	**2.0** (2.8)
PJM	2.9 (**1.9**)	2.8 (**2.3**)	2.4 (**1.7**)	2.7 (**2.0**)	**1.8** (2.4)
SPP	4.9 (**4.0**)	4.5 (**3.8**)	3.9 (**3.1**)	3.1 (**3.0**)	4.2 (**3.0**)
ERCOT	**1.8** (2.7)	2.3 (**2.2**)	2.9 (**2.3**)	**2.5** (3.0)	**1.4** (2.1)
Mean	3.0 (**2.6**)	3.1 (**2.6**)	3.1 (**2.4**)	2.8 (2.8)	**2.4** (2.6)

Note: The above data are forecasting errors in 2020 (outside parentheses) and 2019 (within parentheses). We cover the results from March 1 to July 15 for both years. For each cell, the smaller error items are highlighted in bold.

2.2. Congestion

Transmission network congestion occurs when the available network capacity cannot satisfy the electric power demand without exceeding safety requirements. A heavily congested network appears to be less reliable because the transmission capacity is often insufficient in this case. Given that congestion is related to many factors, it might be effective to conduct an overall assessment by analyzing congestion price data.

Electricity market operators calculate locational marginal prices every day, and congestion prices are one important component. Market clearing theory suggests that these congestion prices are the "shadow prices" of the corresponding operational constraints.

This paper mainly focuses on monthly statistics and calculates the monthly congestion cost as follows.

$$C^{\mathrm{Cong}}_{ym} = \sum_d \sum_t \left(\frac{1}{A} \sum_a \left| \lambda^{\mathrm{Cong}}_{aymdt} \right| \right), \quad \forall y, m \tag{2}$$

where C^{Cong}_{ym} is the congestion cost per megawatt hour for year y, month m. $\lambda^{\mathrm{Cong}}_{aymdt}$ is the congestion price in area a (representing a region in an electricity marketplace), and A is the total number of areas. We apply an absolute function here because the congestion price may become

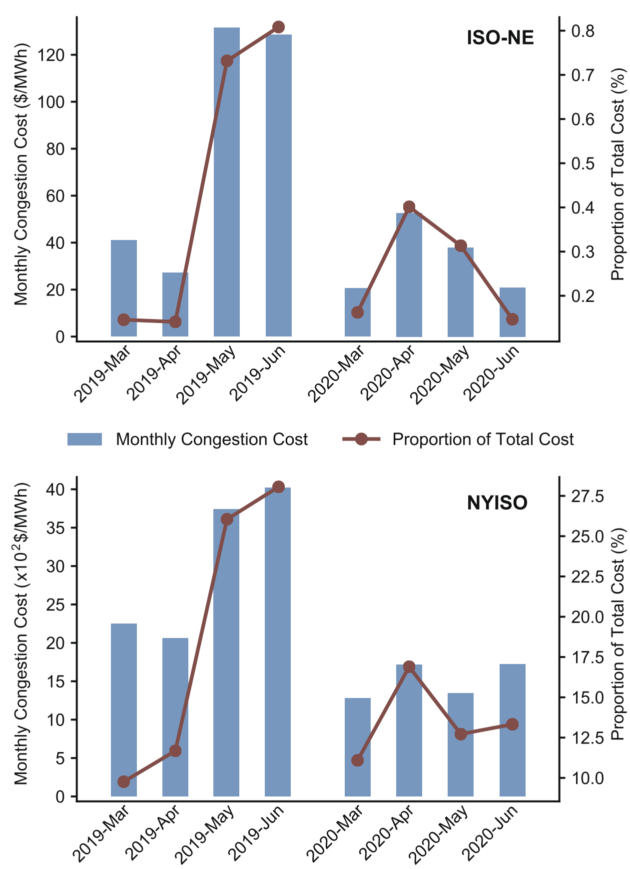

Fig. 4. Monthly congestion statistics in ISO-NE and NYISO. This figure shows both the congestion cost (bar chart) and the associated proportion of total electricity cost (line chart). The results from March to June for 2019 and 2020 are provided for comparison, and a significant drop can be observed in May and June 2020.

negative when the associated power flow direction reverses.

Fig. 4 shows monthly congestion statistics for ISO-NE and NYISO. When compared with 2019 data, congestion costs roughly decreased after the COVID-19 outbreak, especially in May and June. This improvement can be explained by the fact that electricity demand during the COVID-19 pandemic was lower than that during normal times (see Section 4 for more details)—this change is beneficial to transmission capacity (larger redundancy), and congestion is thus less likely to happen. For the proportion of total cost, one can find a slight increase in March and April followed by a significant drop in the next two months. Note that the total electricity prices have rapidly decreased during the COVID-19 pandemic (a more detailed discussion is available in Section 5).

2.3. Forced outage

A forced outage refers to an unexpected shutdown that occurs when some generators are unavailable to produce electricity. More forced outages generally produce higher risk and deteriorate power system security. From a technical perspective, we sum up the forced outage data for each month to develop a high-level criterion.

Fig. 5 shows the monthly forced outage results in PJM and MISO (only available in these two markets). In 2020, the total megawatt-hour of forced outages in PJM is similar to or slightly better than that of the previous two years. This is not true for MISO, especially in March, but an obvious improvement can be found later in June. A possible explanation for the abnormal observation in March is the early hurricane season reported by meteorology analysis [42,43]. Above results show that, until now, no strong evidence has supported a significant and consistent impact. In other words, COVID-19 might have more limited impacts than expected.

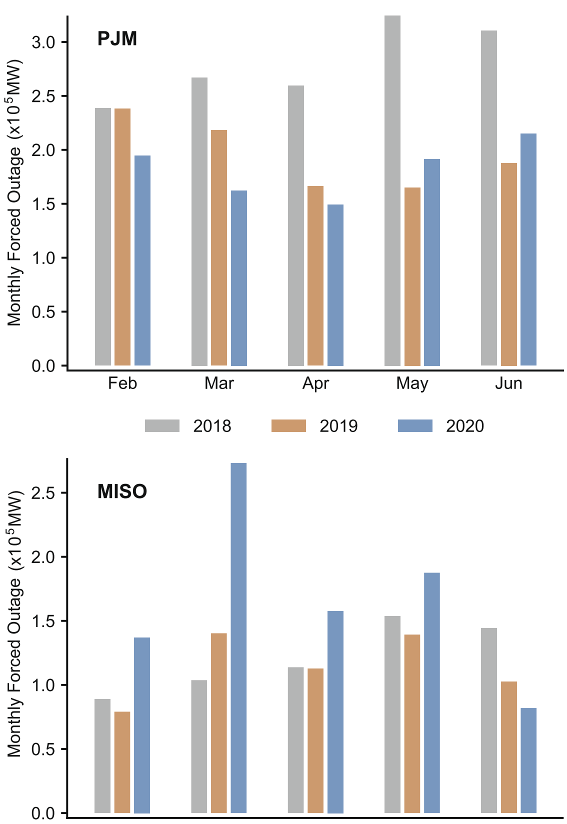

Fig. 5. Monthly forced outage requirements in PJM and MISO. The data from February to June 2020 and the past two years are provided for comparison. Larger changes are found in MISO, especially in February and March.

3. Impact on electric power generation

This section analyzes the changes in electric power generation during the COVID-19 pandemic with a special focus on structural changes as well as renewable generation status.

3.1. Generation mix

The generation mix, or generation structure, refers to the combination and proportion of various types of generators. A key question is whether the generation mix is different during the COVID-19 pandemic, and the answer will provide important evidence of a disproportional impact on different generators.

Fig. 6 shows the generation mix results in SPP and ERCOT, and each figure is divided by dotted lines to show the observations for different years. In SPP, one can clearly observe that carbon-free generation (wind) and less carbon-intensive fuel (natural gas) have a slowly increasing market share, while coal-fired electricity generation continues dropping. A similar trend is also found in ERCOT, with natural gas becoming the major fuel source. For most markets, this is an evolving trend rather than a coincidence, mainly because of ongoing clean energy plans.

A further finding is that no significant difference in structural change (consistently a linear trend) is observed in any electricity market during the COVID-19 pandemic. From a theoretical perspective, the generation

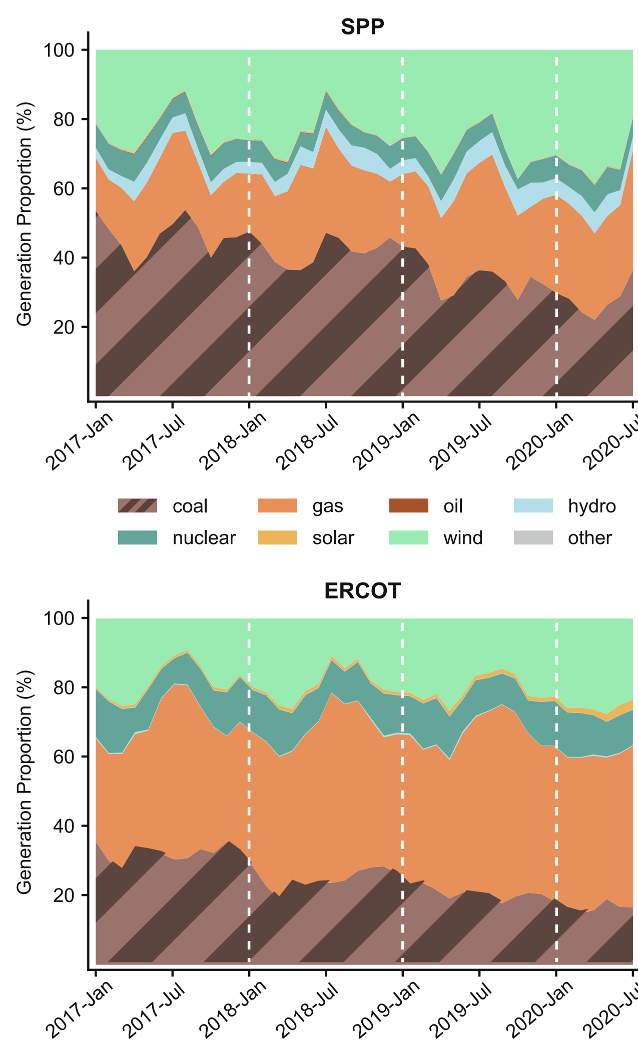

Fig. 6. Generation mix in SPP and ERCOT. The data are recorded from 2017 to 2020 for both markets, showing a clear trend of gradual replacement of carbon-intensive fuel (coal) by other cleaner fuels.

mix is mainly determined by cost competition among different energy fuels. Although the pandemic should have a mild impact on relative fuel costs, cost competition is becoming more intense due to the suppression of total electric power demand. Coal-fired generators have experienced a tough time due to their high cost and low efficiency, while renewable generators are expected to gain market share. These inferences, however, are not totally compatible with our observations, and the difference could be explained by some specific dispatch strategies that keep the generation structure stable for safety concerns.

3.2. Market share and curtailment of renewable generation

Here, we continue the discussion of the previous subsection and provide more quantitative analysis to check whether renewable generators have obtained extra benefits (larger market share due to lower marginal cost) after the COVID-19 outbreak.

Table 2 shows the annual market share of renewable energy from 2017 to 2020. One can trace the proportion change in a row and make the cross-market comparison in a column. Mild changes are found in all electricity markets except ISO-NE and ERCOT. The market shares in CAISO and NYISO remain roughly unchanged, which may indicate a larger curtailment rate.

We formulate an excess change rate to quantify the market share changes during the COVID-19 pandemic. The detailed formula is given below.

$$\eta = \left(\frac{r_{2020}}{2r_{2019} - r_{2018}} - 1\right) \times 100\% \tag{3}$$

where η is the excess change rate, and $r_{2018} \sim r_{2020}$ are the market shares of renewable energy observed in 2018, 2019, and 2020. Assuming a linear growth rate, the denominator term $(2r_{2019} - r_{2018})$ represents the estimated market share without the pandemic. Formula (3) finally calculates a relative change rate between the observed market share and this estimation.

The excess change rates for different markets are given as follows: CAISO (-4.0%), MISO (13.9%), ISO-NE (26.3%), NYISO (-10.5%), PJM (2.6%), SPP (8.5%) and ERCOT (25.8%). These results match the above observations that the renewable generators in CAISO and NYISO might have lower market shares than expected. This outcome is probably due to some operational safety concerns; for instance, an online report [44] found that solar generation during daylight hours in CAISO already outpaces the decreasing electricity demand caused by COVID-19.

We further analyze the renewable curtailment status in SPP and CAISO (only available in these two markets). Fig. 7 shows the monthly renewable curtailment from 2017 to 2020, and one can observe increasing curtailment in 2020 for both markets. Furthermore, CAISO tends to apply a more aggressive curtailment strategy than SPP, and this finding is also compatible with the excess change rates. Although market competition theory suggests that renewable generators can obtain extra benefits, this situation may become quite complex and unclear when considering the curtailment issue.

Table 2
Proportion of renewable generation in U.S. electricity markets [%].

Market	2017	2018	2019	2020
CAISO	21.0	23.8	25.5	26.1
MISO	8.3	7.4	9.1	12.3
ISO-NE	3.1	3.4	3.6	4.8
NYISO	3.2	2.6	3.2	3.4
PJM	2.7	2.6	3.2	3.9
SPP	22.6	23.7	27.1	33.1
ERCOT	18.6	20.5	21.3	27.8
Mean	11.4	12.0	13.3	15.9

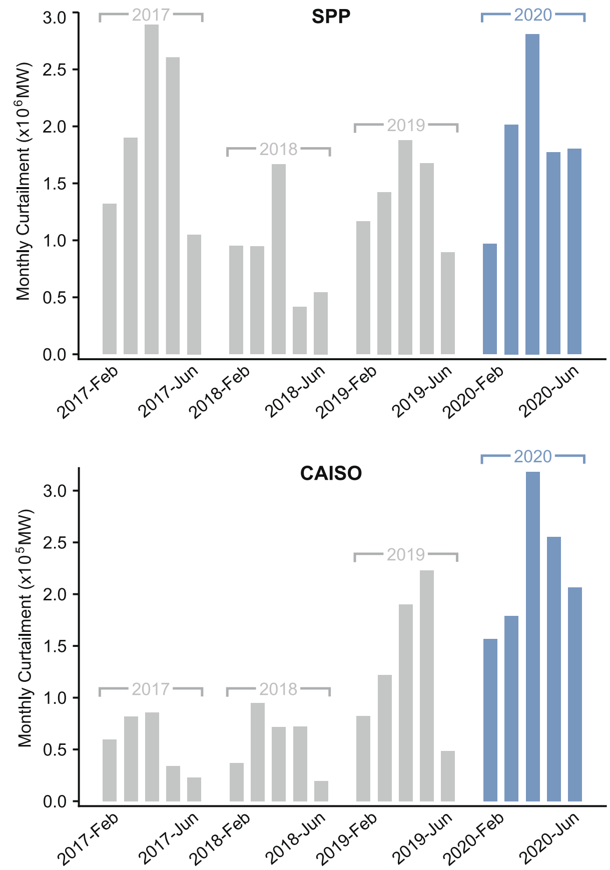

Fig. 7. Monthly renewable curtailment in SPP and CAISO. This figure collects four-year data for comparison. Renewable energy curtailments are observed more frequently in 2020 for both markets, but renewable generators in CAISO have experienced a more severe impact than those in SPP.

Considering the long-term development, renewable generators still face the barrier of high capital costs (high installing expenses), and they rely heavily on a stable and continuous cash flow. This inherent vulnerability might cause more financial difficulties during the pandemic because federal subsidies might be reduced or postponed. More attention, in this respect, should be paid to the long-term financial influences on renewable energy.

3.3. Duck curves and ramping requirements

The duck curve was first developed in 2012 from a CAISO report, and it soon attracted wide interest in both academia and industry. This curve shows the daily imbalance between peak demand and solar energy generation, expressed by the residual demand as follows.

$$R_{ymdt} = D_{ymdt} - G^{\text{Solar}}_{ymdt}, \quad \forall y, m, d, t \tag{4}$$

where R_{ymdt} is the residual electricity consumption (duck curve) for year y, month m, day d, and hour t, and G^{Solar}_{ymdt} is the solar generation at the same time.

Note that the duck curve phenomenon (residual demand drop significantly at noon) merely happens in California because of the high penetration of solar generation. In other markets, e.g., ERCOT and SPP, solar grows fast but only accounts for a small proportion.

Fig. 8 compares the duck curves from 2018 to 2020, and the data from March to mid-July of each year are used. The average duck curve profiles are shown in the middle with two uncertain intervals (25%~75% and 10%~90% quantile intervals), which are calculated as follows: given

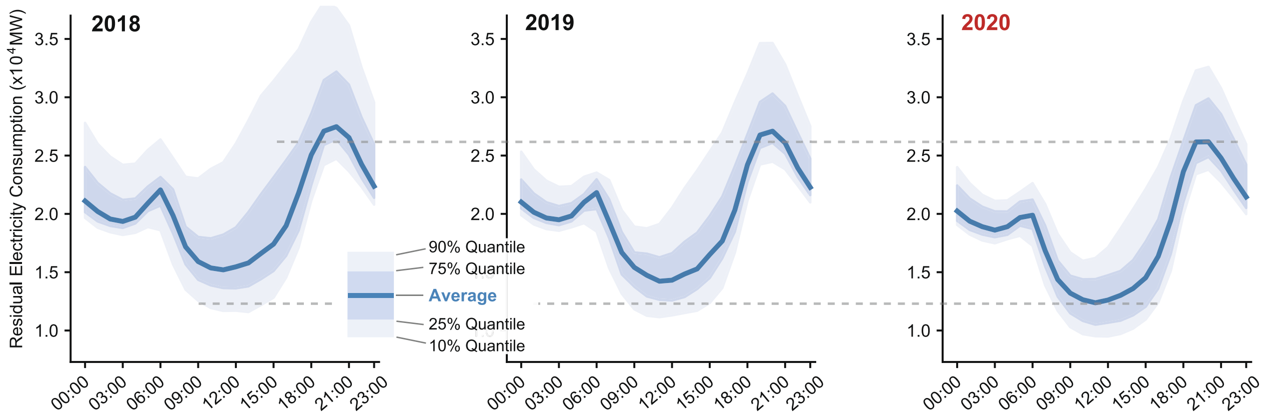

Fig. 8. Three-year duck curves in CAISO. The uncertainty intervals are made up of the 10%~90% and 25%~75% quantiles. A larger peak-valley difference and peak-valley ratio in 2020 can be verified when compared with the past two years.

a typical year y and hour t, the marginal distribution of the residual demand profile data is expressed as $R_{ymdt} \sim \widehat{F}_{yt},\ \forall m, d$; then, $\widehat{F}_{yt}$ can be visualized in Fig. 8 with four quantiles, i.e., $\widehat{F}_{yt}^{-1}(10\%), \widehat{F}_{yt}^{-1}(25\%)$, $\widehat{F}_{yt}^{-1}(75\%)$ and $\widehat{F}_{yt}^{-1}(90\%)$.

Fig. 8 clearly exhibits a shift down in the duck curve of 2020, mainly due to the reduction in electricity consumption. The valley part shrinks slightly more than the peak part, resulting in an enlarged peak-valley difference and a larger peak-valley ratio. This pattern will increase the ramping requirement and operation risk as well. We then consider the maximal hourly ramp-up and ramp-down requirements and calculate the average values for each year. The average ramp-up requirement in 2020 is 4284.5 megawatts, higher than 2019 (3886.2 megawatts) and 2018 (3497.7 megawatts). Again, we find the highest ramp-down requirement, 3444.2 megawatts, in 2020, compared with 2019 (3212.5 megawatts) and 2018 (3195.9 megawatts).

4. Impact on electric power demand

This section concentrates on the changes in electric power demand across all U.S. electricity markets. A typical case study of New York state and a cross-market comparison are fully discussed.

4.1. Demand profiles in New York state

The demand side is believed to have experienced a significant change

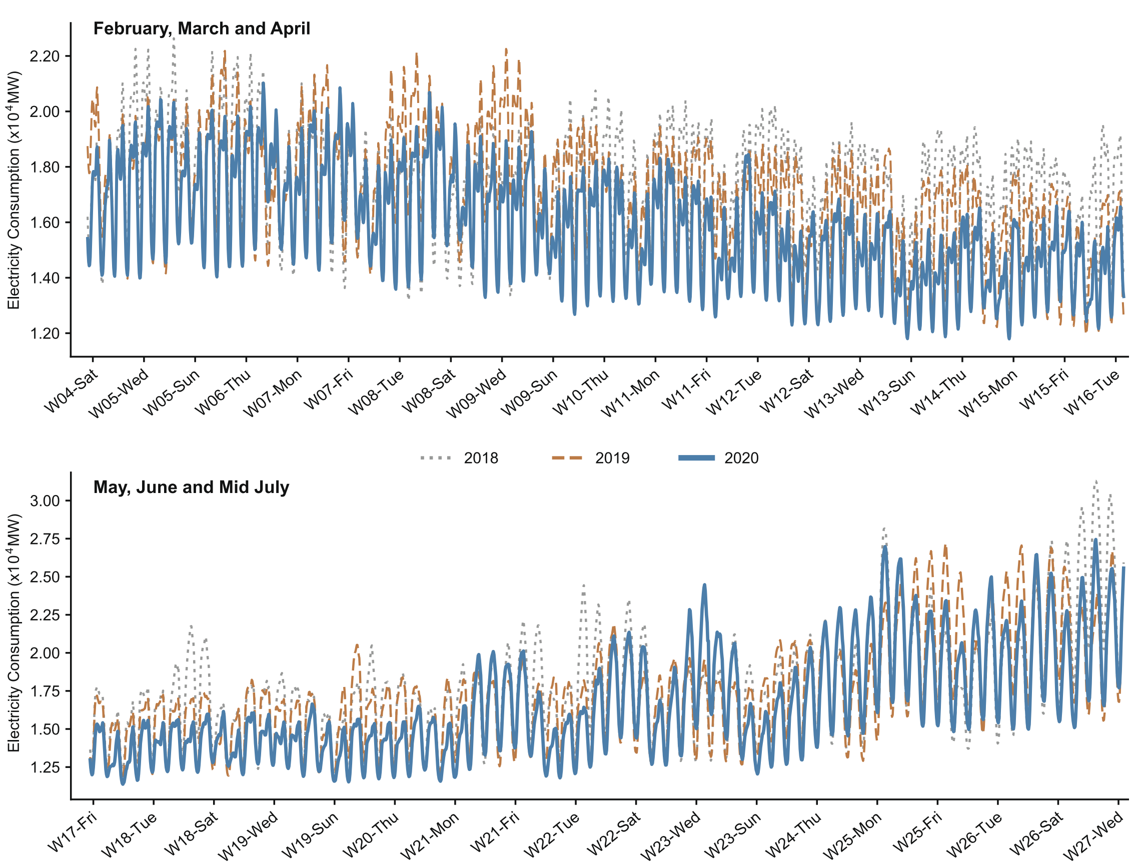

Fig. 9. Hourly electricity consumption in New York state from 2018 to 2020. The data from February to May are aligned by weekday. Compared with the past two years, a significant drop can be observed since March 2020, and this trend continued until a rebound in the last week of May.

after the COVID-19 outbreak, and we first focus on the epicenter NYISO (located in New York state).

Fig. 9 shows the electricity consumption from February to mid-July in the last three years. These three-year data are properly aligned to allow comparisons between the same weekdays. Technically, the week alignment is implemented by using the following formula.

$$\begin{bmatrix} m' \\ d' \end{bmatrix} = W_{y-1}^{-1}\left(W_y\left(\begin{bmatrix} m \\ d \end{bmatrix}\right)\right), \quad \forall y, m, d \tag{5}$$

where y, m, d are the associated year, month, and day, respectively. $W_y(\cdot)$ is a transform function that converts a calendar date to a week-weekday format, while $W_{y-1}(\cdot)$ can do an opposite transform for the previous year.

Formula (5) finally derives an aligned date pair (y, m, d) and $(y-1, m', d')$ so that both dates are the same weekday of the same week in the corresponding year. This alignment helps eliminate the undesired impact of week patterns.

As shown in Fig. 9, electricity consumption starts dropping in March and remains low until late May. During this period, the average hourly reduction rate is 6.4%, and the maximal rate is 25.3% when taking the 2019 data as the baseline. A rebound phenomenon can be clearly observed in the last week of May (week 21 in Fig. 9), mainly because of gradual reopening policies. This pattern continued until July, by which the demand had almost recovered to normal levels.

We next plot and compare the demand profiles features. For all the subfigures in Fig. 10, the daily averaged load profiles are plotted in the middle with two uncertain intervals. These intervals are calculated by means of a method similar to that in Section 3.3.

Fig. 10 compares the situations in February, April, and June. One can

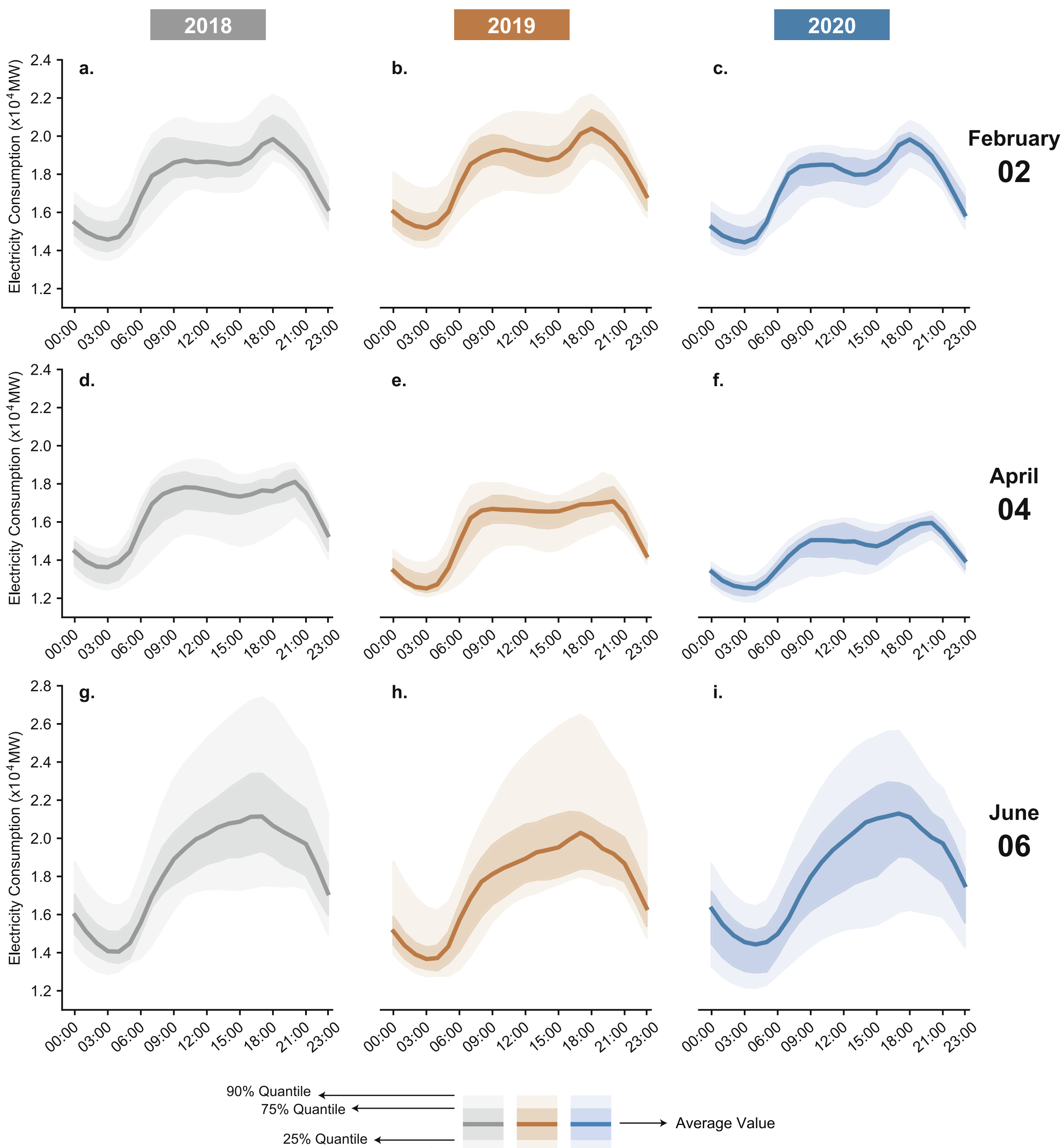

Fig. 10. Comparison of daily averaged electricity demand profiles in NYISO. Each column shows the profile for one year (2018–2020), and each row shows the profiles for different month (February–May). The 10%~90%, 25%~75% quantiles are also given. The results show a significant change in March 2020.

find a significant drop from February to April and a rapid rebound in June. Further comparisons are made by calculating the coefficient of variance for these profile curves. The results show that the curve in April 2020 is flatter than those in the previous two years, with a 14.5% drop in the coefficient of variance. One can also observe a relatively smooth morning ramping in April 2020, which is beneficial for system operation. The daily load profiles seem to be less stochastic in April 2020, while the profiles in the other two months exhibit more fluctuation. Moreover, very few differences can be identified in June 2020 when compared with 2018 and 2019.

To further eliminate the impact of weather factors, we apply an ensemble backcast model to our previous work [39] to produce an adjusted estimation of the demand reduction rate. Fig. 11 shows the estimation results with several date labels highlighting some important events during the COVID-19 pandemic. We find a good match between demand changes and those important COVID-19 events in New York state, especially in the fast-developing period from late February to mid-April. This observation, from another perspective, reveals a hidden relationship between electric power demand data and public health data.

4.2. Demand change across different markets

For cross-market comparison, we extend the previous analysis to other markets and highlight some key observations as follows.

The results show that the northeast region has experienced the greatest influence, while a limited impact can be observed in the southern area. This finding is probably due to different electricity consumption behaviors, and electricity use in the southern area is shifting rather than decreasing. Before June, large load changes often occur in the hardest-hit areas, but an exception is late June when an abnormal growth in case numbers happened in Texas. In terms of the dynamic trend, CAISO is the first market to start recovering in mid-May, nearly one or two weeks earlier than other markets. We also find an obvious rebound in the demand reduction rate in CAISO (which first drops from late April to early May and rebounds for a few days before a second drop after mid-May) and ERCOT (which first drops from mid-May to late May and rebounds until early June before soon dropping again).

5. Impact on wholesale electricity price

This section analyzes the pandemic's impact on wholesale electricity prices (specifically, day-ahead locational marginal prices). We first develop an abnormal price index and then conduct a full assessment across all U.S. electricity markets.

5.1. Abnormal price index

Locational marginal prices play a crucial role in electricity markets and contribute to balancing electric power generation and demand efficiently. Since these prices are relatively stochastic in nature, it is unsatisfactory to analyze them in the same way as electricity demand (the uncertainty intervals will be very wide). Thus, the abnormal price index is developed as a more reliable tool for price analysis. It is defined as follows.

$$I\left(\lambda_{ymdt}\right) = \left|2\widehat{F}_m\left(\lambda_{ymdt}\right) - 1\right|, \quad \forall y, m, d, t \tag{6}$$

where λ_{ymdt} is the day-ahead locational marginal price of year y, month m, day d, and hour t. $I(\cdot)$ is the proposed index, which lies between zero and one. This index quantifies the abnormality of a typical price, and a larger index value represents a more unusual observation. $\widehat{F}_m(\cdot)$ is the cumulative distribution function for the prices in month m. We will show in the next subsection that monthly distributions are stable and suitable for analyzing these price changes.

The statistical meaning of the above index is explained by the probability density function shown in Fig. 12. For a given price, the index denotes a possibility that measures how close this price is to the mean value. For example, if a price observation is located within the 25% and 75% quantiles, we obtain an index value below 0.5, which is

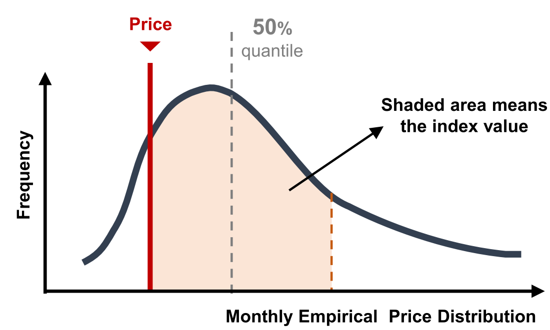

Fig. 12. Statistical illustration of the proposed abnormal price index. The basic idea is calculating how near a price observation is to the mean value. This index can reliably eliminate some stochastic factors when assessing price changes. The index value lies in $[0, 1]$, and a larger value means a higher possibility of abnormality.

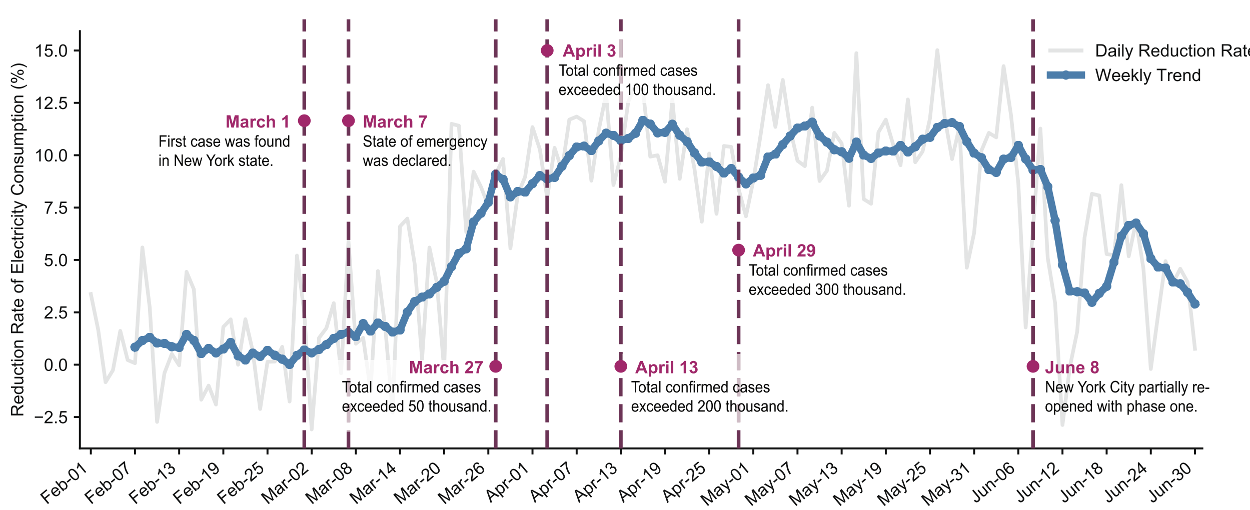

Fig. 11. Time-varying reduction rate of the electric power demand in NYISO during the COVID-19 pandemic. The weekly trend is calculated by means of a moving average technique. Some important events for New York state are highlighted in the timeline.

considered normal.

Since this abnormal price index has a clear statistical meaning and a concise expression, it is extremely suitable for analyzing price changes with uncertainty.

5.2. Price distribution in the New England area

As a typical example, Fig. 13 shows the price distributions for several years in the New England area. We select the price data from March to mid-July to derive the frequency graph and highlight the highest frequencies. A clear observation is that the distributions in 2017, 2018 and 2019 look similar but quite different from that for 2020 (this remains true even for a single month). A more concentrated distribution is found in 2020 with a shrinking mean value, which reflects continuous observations of low prices. To see this, the average prices from March to mid-July drop from approximately US$30 before 2020 to US$18.13 in 2020.

Extensive testing beyond Fig. 13 is conducted, and we finally find that the monthly price distributions are stable enough to eliminate the stochastic influences but remain high precision. The daily price data are more sensitive to some unexpected outliers than electricity demand, and those outliers are unfortunately common. For example, in April 2018, the average price at 12 PM is US$42.87, 66% higher than that in 2019, and the uncertain interval between the 25% and 75% quantiles is US$31.12, 72.6% of the average price (but for electricity demand, this number never exceeds 21%).

This finding also implies that the proposed abnormal price index can show reliable performance by analyzing the price distributions. Fig. 14 plots the trend of the abnormal price index from February to mid-July 2020. Some important events related to COVID-19 are highlighted, including declaration dates for state-of-emergency orders.

A surprising finding is that the index values are already very high before the state-of-emergency declarations, which indicates that another factor is driving the prices down before the COVID-19 outbreak. The most likely factor is the natural gas price collapse, which can be verified by comparing Fig. 14 with the gas price curve [45]. We next substantiate that the electricity prices are experiencing a double impact of the gas price and COVID-19 pandemic. To see this, we calculate the Pearson correlation coefficient between the abnormal index and gas price, and analyze the data before and after the declaration dates for state-of-emergency. The results show that the coefficient drops from −0.502 (moderate negative relationship) to −0.045 (weak relationship), and this is probably due to an offset effect of the above two factors. An illustrative evidence in late April is that the abnormal index still remains high but the gas price quickly rebounds (it is expected that COVID-19 has an opposite effect).

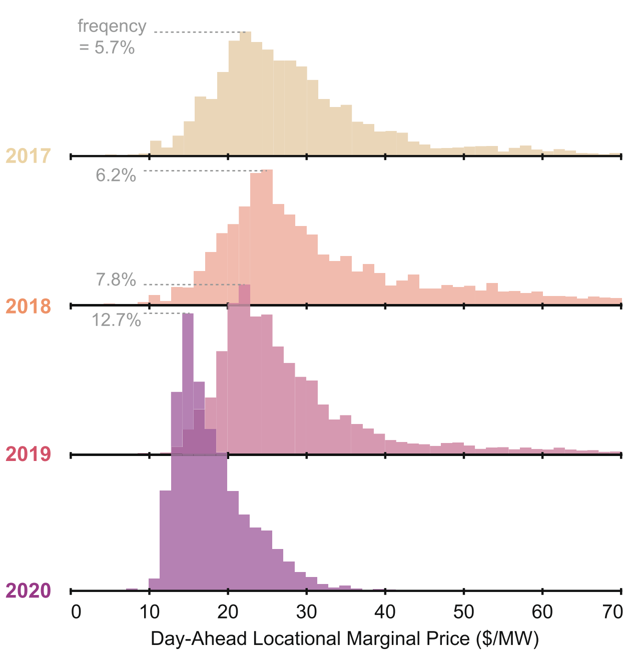

Fig. 13. Day-ahead locational marginal price distribution in ISO-NE. The data from March to mid-July 2020 and the past four years are analyzed. Obvious changes in price distribution can be verified by a lower mean value as well as a higher peak (peak frequencies are provided).

5.3. Price distribution change across different areas

To conduct a cross-market comparison, we apply a Wasserstein probability distance metric to quantify the price change during the COVID-19 pandemic. The price change for year *y* can be formulated as follows.

$$s_y = \mathrm{WD}\left(\mathrm{Vec}\left(\lambda_{ymdt}\right) - \mathrm{Vec}\left(\lambda_{\mathrm{hist}}\right)\right), \quad \forall y \tag{7}$$

where s_y denotes the price change for year *y* that is calculated by a Wasserstein distance function $\mathrm{WD}(\cdot)$. $\mathrm{Vec}(\cdot)$ is a vectorization function to place all the price data from March to mid-July in a one-dimensional array. λ_{hist} represents all the historical price data accordingly.

Table 3 presents the price change results together with some public health statistics. Significant price distribution changes can be found in the hardest hit areas, especially for NYISO, ISO-NE, and PJM. Additionally, those markets in the northeast region has experienced a larger price drop than the other areas. Since gas prices across the nation are similar, the findings in Table 3 roughly capture the intensity of the pandemic's impact across different marketplaces.

6. Conclusion

This paper conducts a comprehensive assessment of the pandemic's impacts on U.S. electricity markets and bulk power systems. Drawing on the COVID-EMDA$^+$ data hub, we provide some strong evidence that the power sector was highly influenced from March to May, entering a recovery period after June. We also find very diverse impacts in different marketplaces, so market-specific analysis is critically important. Electric power demand and prices are more heavily affected than power grid operations and electric power generation.

Based on current observations, the impact of COVID-19 may not be a high risk for existing power systems, but we should pay more attention to possible shocks in the near future (e.g., a second wave in the winter) and some mid- to long-term influences. It is also important to focus on disproportionate impacts on utility companies and consumers. All these issues require considerable effort from the whole society.

Although COVID-19 will not disappear immediately, the energy community can minimize potential adverse impacts by monitoring the situation. Our future work involves developing novel methods to understand the complex economy-energy relationship during the COVID-19 pandemic, which can provide further insights to prepare for an uncertain future.

CRediT authorship contribution statement

Guangchun Ruan: Methodology, Software, Data curation, Visualization, Writing - original draft, Writing - review & editing. **Jiahan Wu:** Software, Data curation, Writing - original draft, Writing - review & editing. **Haiwang Zhong:** Supervision, Methodology, Writing - review & editing. **Qing Xia:** Supervision, Writing - review & editing. **Le Xie:** Supervision, Resources, Methodology, Writing - original draft, Writing - review & editing.

Declaration of Competing Interest

The authors declare that they have no known competing financial

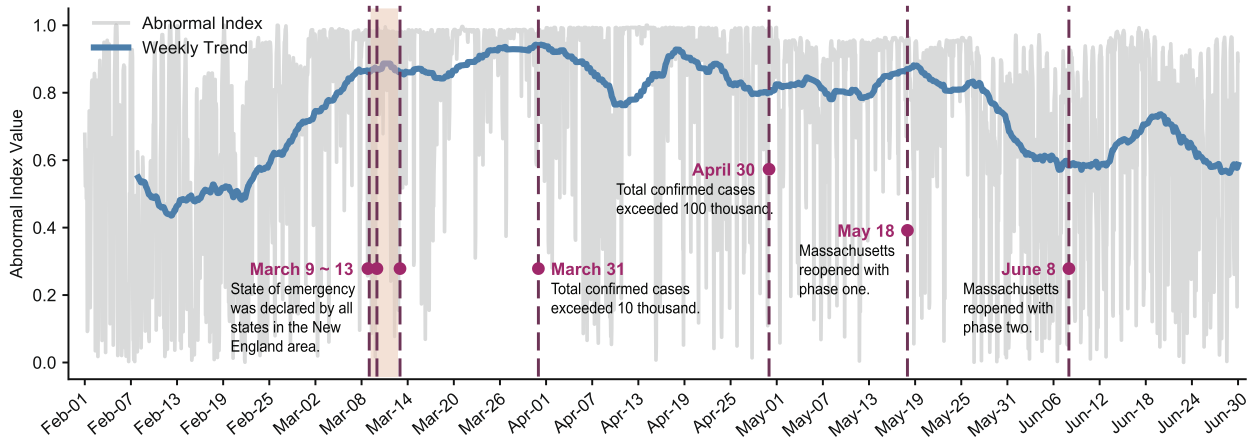

Fig. 14. Time-varying values of the abnormal price index in ISO-NE during the COVID-19 pandemic. The weekly trend is obtained by means of a moving average technique. The declaration of state-of-emergency orders and other important events are highlighted in the timeline. The increasing abnormal price index values before March imply that prices has already gone down prior to the pandemic.

Table 3
Price changes and public health statistics in U.S. electricity markets.

Market	Price Distribution Distance	Total Confirmed Cases [$\times 10^3$]	Virus Infection Rate [%]
CAISO	7.848	355.3	0.90
MISO	8.678	771.1	1.28
ISO-NE	11.774	186.6	1.26
NYISO	10.407	404.0	1.54
PJM	11.548	702.3	1.05
SPP	8.582	117.9	0.77
ERCOT	9.680	305.5	1.05

interests or personal relationships that could have appeared to influence the work reported in this paper.

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