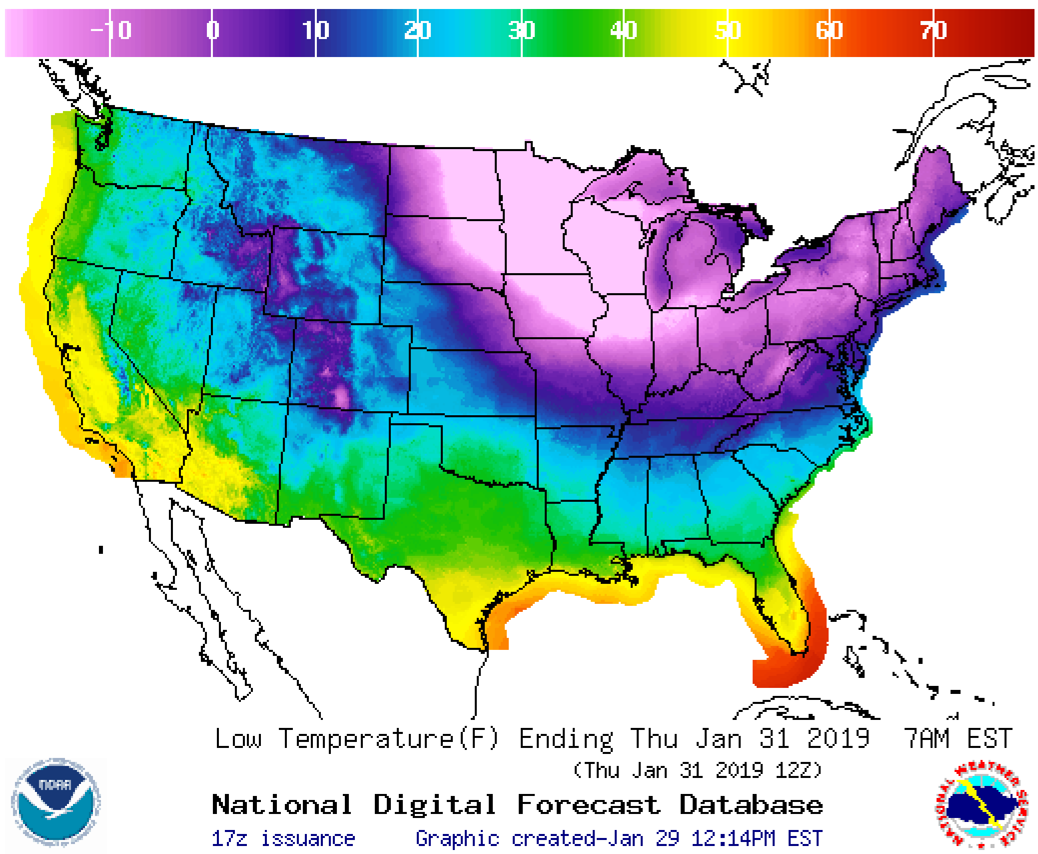
Cold Weather Operations Summary

January 28 – 31, 2019

Following is a summary of the operations that occurred during the week of January 28. The information should be considered preliminary and may be subject to change based on further review. This summary is being provided in advance of the Operating Committee meeting on February 5, 2019.

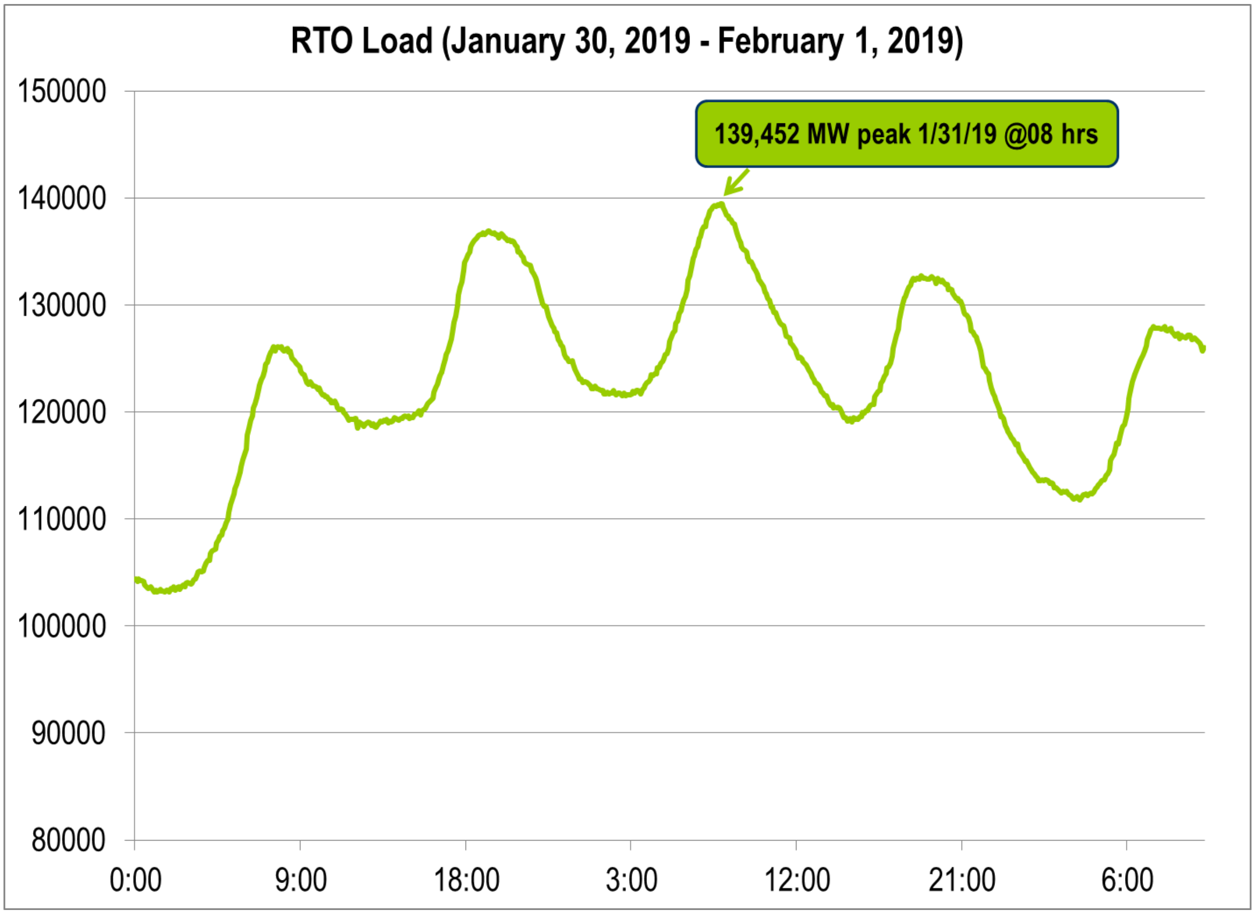
During the week of January 28 the coldest air mass of the winter season so far, moved into the PJM footprint. The cold temperatures began to move into the western part of the RTO as early as Tuesday and then spread east across the RTO for the second part of the week. Daytime temperatures in the ComEd zone on Tuesday were right around zero degrees. By Wednesday morning temperatures across most of the western part of the RTO were in the single digits or colder. By Thursday morning temperatures in the Mid-Atlantic area of PJM were in the single digits while most of PJM West was below zero. Morning low actual temperatures (not wind chill) on Thursday in the ComEd transmission zone were negative 24 degrees. Temperatures moderated on Friday.



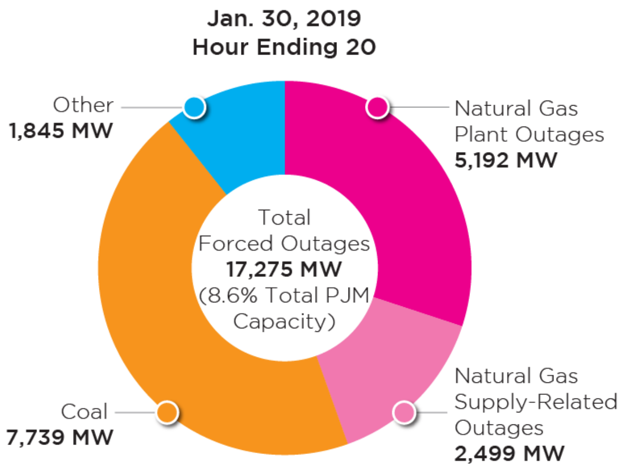
In anticipation of the cold weather PJM issued a Cold Weather Alert for the ComEd transmission zone for Tuesday, a Cold Weather Alert for PJM West for Wednesday and a Cold Weather Alert for the entire RTO on Thursday and Friday. In addition PJM hosted an SOS conference call on Tuesday to review expected system conditions with generation owners and transmission owners.

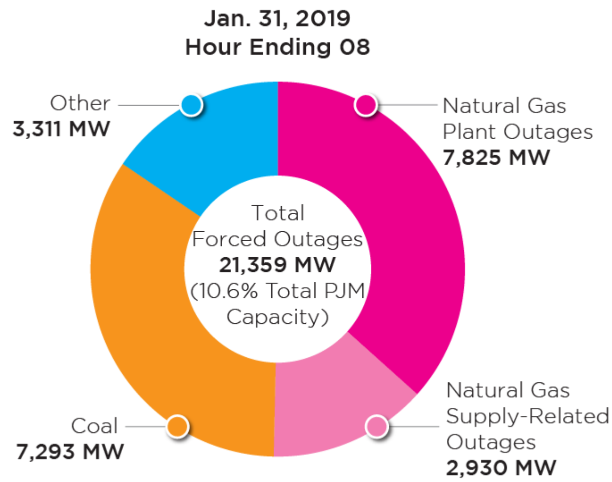
The load increased significantly as the frigid air mass moved into the RTO. The figure below shows the RTO load over the period between Wednesday, January 30 and Friday, February 1. The overall RTO load continued to increase as the cold weather moved from the western region and into the mid-Atlantic zone of the RTO. By

Wednesday the cold air was firmly entrenched in the west and temperatures were dropping through the day in the Mid-Atlantic zone as a cold front moved off the coast. The Wednesday evening peak load was approximately 136,000 MW. The highest RTO load for the period occurred on Thursday morning. The RTO peak load on Thursday morning approached 140,000 MW.



Overall generation performance through the period was good. Forced outages were slightly greater than normal which is typical for periods of extreme cold temperatures. PJM has compiled preliminary generation outage information for the Wednesday evening peak period and the Thursday morning peak period. The figures below show the total generation forced outages by fuel type for the two peak periods.

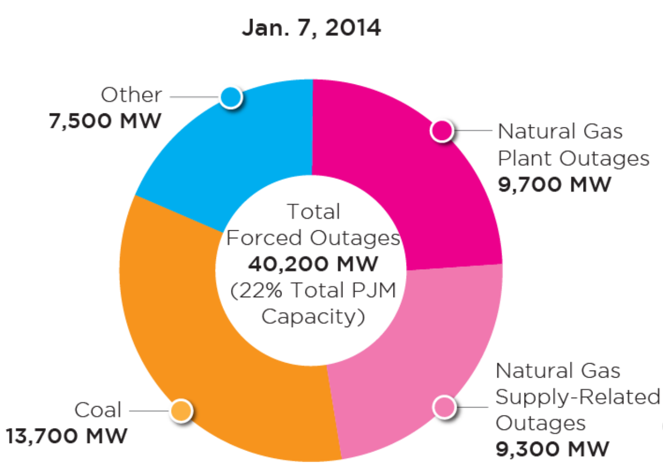


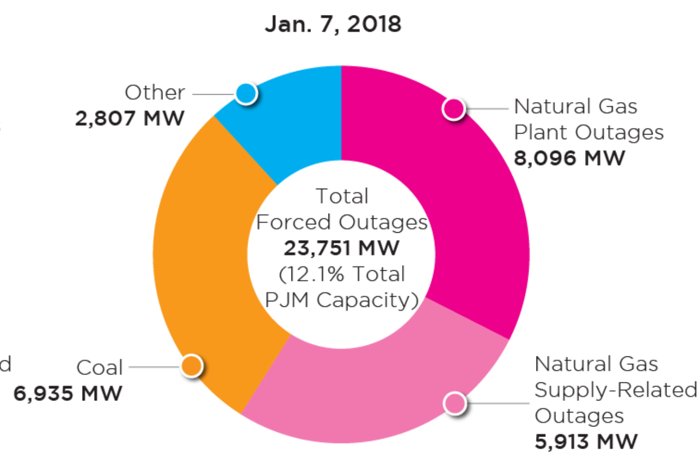


As of Jan. 31, 2019. This data should not be used as the basis for decision-making.

The forced outages for the Wednesday evening peak shown in the figure above on the left were just over 8.6 percent of the total PJM capacity. The forced outages for the Thursday morning peak shown in the figure above on the right were just over 10.6 percent of the total PJM capacity.

By way of comparison, generation forced outages by fuel type for the 2018 winter peak are shown to the right. Generation forced outages by fuel type for the 2014 polar vortex outbreak are shown on the following page. The forced outage rates experienced this past week are lower than the forced outage rates that occurred during the winter peak of 2018 which were 12.1 percent and significantly lower than the forced outage rates experienced during the polar vortex event of 2014 which were 22 percent. Attachment A contains additional generator performance analysis.





Market Operations

Locational Marginal Prices (LMPs) were moderate throughout the two days, averaging $54/MWh and $58/MWh on Wednesday and Thursday, respectively. Reserve market clearing prices (MCP) remained close to $0/MWh for the majority of the two days. However, LMPs and reserve market clearing prices were elevated during the Wednesday evening and Thursday morning peaks.

	Wednesday January 30 Evening Peak (Hours: 17, 18, 19, 20)			Thursday January 31 Morning Peak (Hours: 7, 8, 9, 10)		
	Average	**Maximum**	**Minimum**	**Average**	**Maximum**	**Minimum**
RTO LMP ($/MWh)	$ 117	$ 747	$ 53	$ 73	$ 144	$ 31
MAD Synchronized Reserve MCP ($/MWh)	$ 32	$ 600	$ 0	$ 12	$ 102	$ 0
RTO Synchronized Reserve MCP ($/MWh)	$ 26	$ 300	$ 0	$ 12	$ 102	$ 0
RTO & MAD Non-Synchronized Reserve MCP ($/MWh)	$ 12	$ 260	$ 0	$ 0	$ 0	$ 0

There were two periods of shortage pricing in the synchronized reserve market, both of which occurred following the loss of generation. On Wednesday as we approached the evening peak following the forced outage of a generator in the western part of the RTO, MAD and RTO synchronized reserve prices were $600/MWh and $300/MWh, respectively, and the energy price approached $750/MWh. The second period of shortage pricing occurred in the early morning hours on Thursday. The system energy price was just over $1,000 following the loss of a generator in the eastern part of the RTO, and MAD and RTO synchronized reserve prices reached just over $900/MWh and $600/MWh, respectively.

Appendix

Based on the data in Figure 1: and Figure 2: most retiring units were offered as must run in the Day-Ahead Market (must run indicates that the generating unit is self-scheduling), and the data in the figures includes nuclear, oil, gas, coal, etc. resources. Approximately 5 percent of retiring unit ICAP was picked up economically in the Day-Ahead Market, and approximately 6 percent of retiring unit ICAP was available in reserve shutdown. Forced outage rates for retiring units ranged from 18 percent to 23 percent, this is approximately double the PJM RTO forced rates during the same peaks which ranged from 7.0 percent to 10.6 percent.

Figure 1: Announced Retirement Generator Performance (Capacity)

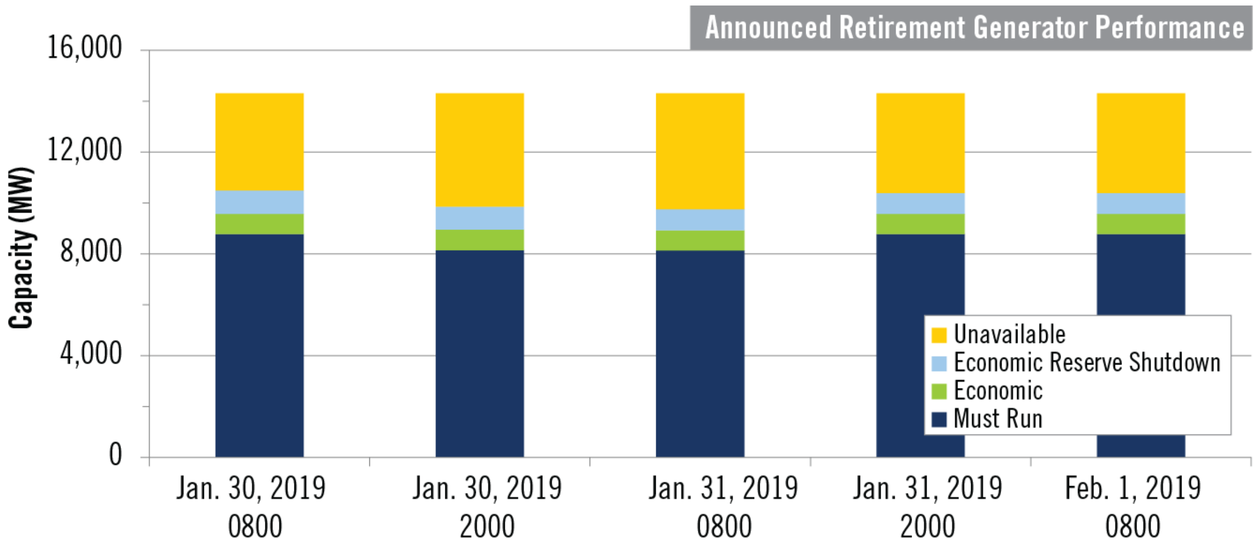


Figure 2: Announced Retirement Generator Performance (Percent)

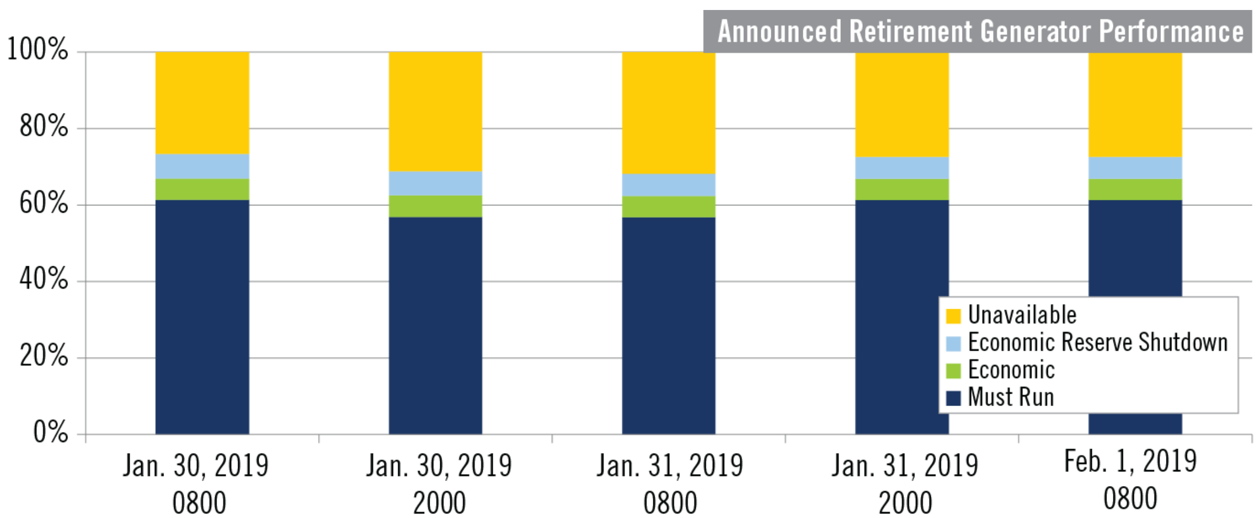


Figure 3:contains data for scheduled MW in Day-Ahead Market from units not committed in RPM or units committed partially in RPM. The blue portion of the bar contains scheduled MW in Day-Ahead Market from units that are not committed in RPM. The green portion of bar contains scheduled MW from partially committed units in RPM. These MW are scheduled in Day-Ahead Market above their cleared ICAP MW.

Figure 3: **Day-Ahead Scheduled MW from Uncommitted Capacity in RPM**

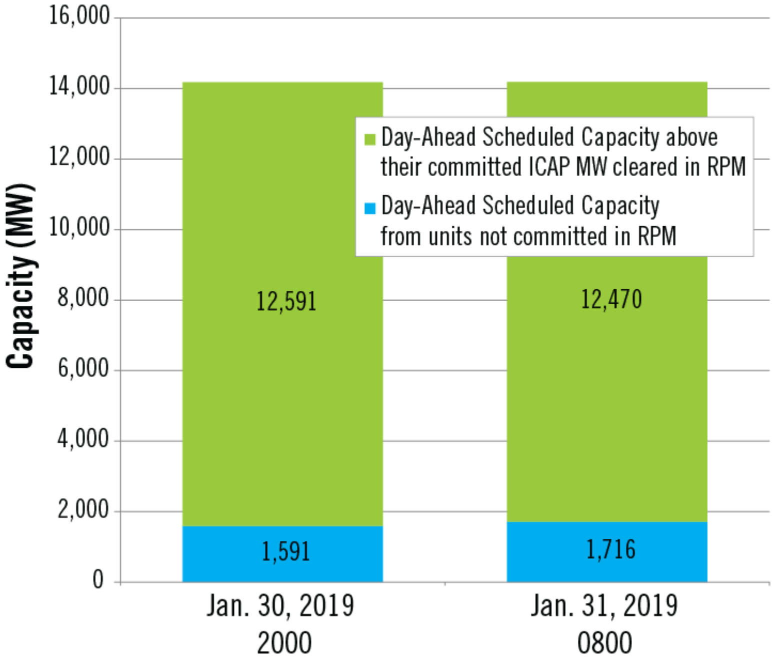


Figure 3:contains scheduled and unscheduled capacity in Day-Ahead Market from committed RPM units. The blue portion of the bar contains unscheduled MW but available to be scheduled in Day-Ahead Market from units committed in RPM. The green portion of bar contains scheduled MW in Day-Ahead Market from units committed in RPM.

Figure 4: **Day-Ahead Scheduled and Unscheduled MW from Committed by RPM units**