Of Polar Vortexes and PJM Price Spikes

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Executive Summary

As discussed in the previous Polar Vortex white papers,[1] extremely high power prices create significant commercial opportunities that can be partly predicted in advance and also highlight the need for careful attention to reliability policy and planning due to changes in resource mix and market rules. These conclusions have been dramatically reinforced by the developments of the past few days – January 20-24, 2014. Delivered natural gas prices in the east reached all-time record levels of well above $100/MMBtu, and also well above prices in early January 2014 – one key delivered gas price was 3 times higher, $123/MMBtu versus $40/MMBtu. Meanwhile the gas price at Henry Hub, the traditional benchmark for natural gas prices, was less than $5/MMBtu. Indeed, while some gas prices were at record levels in the east, at a distance of less than 100 miles in some cases, gas prices were as low as Henry Hub.

This resulted in extremely high wholesale power prices. The costs of producing electricity also exceeded the wholesale generator offer cap which dangerously and inadvertently created incentives not to perform, and thus, endangered grid reliability. Some generators were forced to run while losing money. Emergency action by FERC is expected to alleviate this situation by providing "make-whole" payments to generators. However, emergency action does not address the magnitude of the price premiums that are resulting. To illustrate, were recent record prices in the Washington DC area to continue for just 7 days, the annual cost of wholesale power would approximately double. While a lesser result is more likely, there are huge potential implications for consumers and commercial entities, especially those not hedged and caught unaware.

Careful policy and planning changes are needed to accommodate the new power gas relationship. For example, PJM's increased implementation of summer only procurement puts it in danger during strong winter cold snaps of extremely high prices and reliability deficiencies. PJM needs to appropriately plan for both peaks, summer and winter, as well as provide appropriate pricing signals to generators, perhaps by tying generator offer caps to gas prices, rather than leaving them administratively set at $1000/MWh, and find the right balance between automatic market mechanisms and administrative action.

PJM Natural Gas Prices Hit Record

Delivered natural gas prices in the downstream eastern gas markets (specifically, New England, the New York City metro area, and portions of the Mid-Atlantic) reached an all-time record level, even significantly surpassing levels reached just 2 weeks earlier, during the polar vortex. As shown by the figures below, gas prices reached $123/MMBtu on Wednesday January 22nd, which is a premium of up to 2,520 percent over Henry Hub, the traditional commodity market location in Louisiana. High prices due to natural gas delivery shortages were predicted, though not the specific record levels.[2]

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1 http://www.icfi.com/insights/white-papers/2014/polar-vortex-energy-pricing-implications-commercial-opportunities-and-system-reliability and http://www.icfi.com/insights/white-papers/2014/commercial-opportunities-and-system-reliability

2 http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/dec182013/a3_icf_phase_2_gas_study_presentation.pdf

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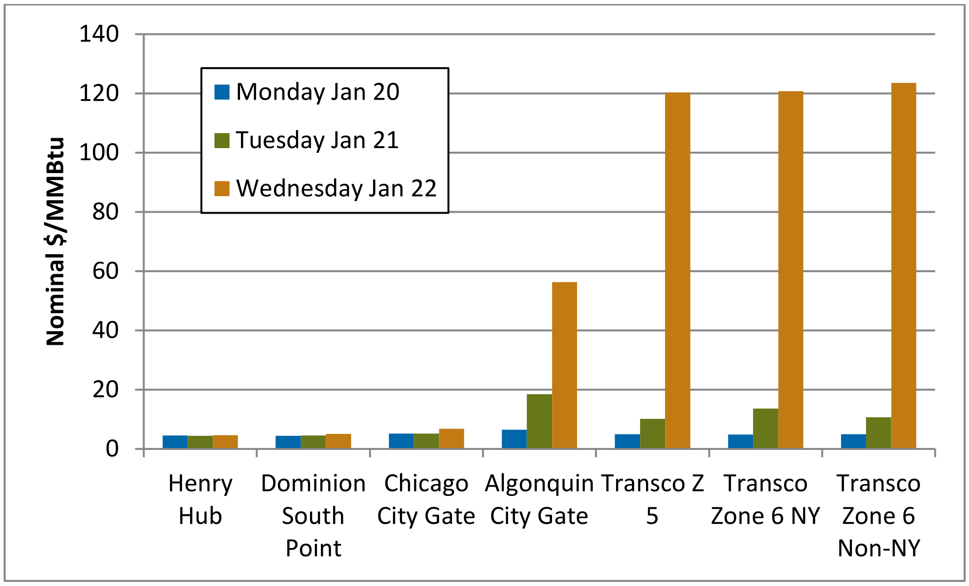
Since 1969, ICF International (NASDAQ:ICFI) has been serving government at all levels, major corporations, and multilateral institutions. With more than 60 offices and more than 4,500 employees worldwide, we bring deep domain expertise, problem-solving capabilities, and a results-driven approach to deliver strategic value across the lifecycle of client programs.

At ICF, we partner with clients to conceive and implement solutions and services that protect and improve the quality of life, providing lasting answers to society's most challenging management, technology, and policy issues. As a company and individually, we live this mission, as evidenced by our commitment to sustainability and carbon neutrality, contribution to the global community, and dedication to employee growth.

Figure 1. Regional Gas Pricing – January 20, 21 and 22



Source: SNL

In contrast, at locations just 100 miles or so upstream of the congested market areas, such as Dominion South Point in Pennsylvania, gas prices were on par with Henry Hub.

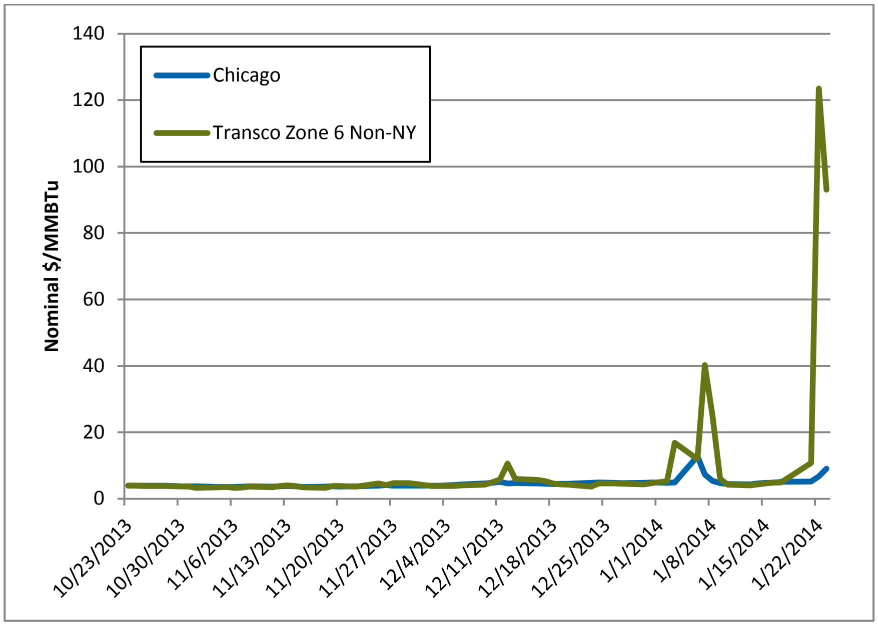
Figure 2. Regional Gas Pricing Relative to Henry Hub

Day	Henry Hub ($/MMbtu)	Dominion South Point	Chicago City Gate	Algonquin City Gate	Transco Z 5	Transco Zone 6 NY	Transco Zone 6 Non-NY
Monday Jan 20	4.55	-3%	13%	42%	9%	7%	8%
Tuesday Jan 21	4.39	3%	18%	321%	130%	211%	144%
Wednesday Jan 22	4.61	11%	46%	1120%	2508%	2519%	2579%

Source: SNL

As can be seen in the figure below, the extreme price volatility seen in the eastern gas market was not matched in western PJM. For the past three months, gas prices in Chicago and New Jersey were within $1/MMBtu of each other. During the polar vortex earlier this month and the cold snap this week, that difference jumped, as Transco climbed to $40/MMBtu January 7th and $123/MMBtu January 23rd.

Figure 3. Gas Pricing Comparison between Chicago and Transco Zone 6 (New Jersey)



Source: SNL

Consequences for Wholesale Power Prices

As shown in the figure below, eastern PJM power exceeded the generator offer cap on January 22nd. The extremely high prices were also accompanied by the need to call operating reserves in some areas, notably the areas around Washington, DC and Baltimore. This story is still developing; on Friday January 24th at 7:00 am, PEPCO real-time energy pricing hit $2,200/MWh and Dominion reached an even higher price, $2,600/MWh. ICF is continuing to monitor this situation as it unfolds.

Also, the costs of producing incremental gas-fired power were so high as to be above the generator offer cap. The highest price that a power plant can bid into the market in PJM (known as the generator offer cap) is $1,000/MWh, even if their costs are higher. For example, natural gas prices hit $123/MMBtu on Wednesday in New Jersey. The fuel portion of the operating cost of a marginal gas fired peaking plant[3] would be $2,706/MWh, but it could bid only $1,000. A 1000 MW plant would be losing $1,706,000 every hour or 287 million dollars per week. While this is only an illustrative situation designed to highlight the potential consequences of not allowing generators to fully recover their fuel costs, it underlines the risk to the system and generators created by the record high gas prices.

PJM made an announcement that because FERC was closed on Tuesday January 21 (due to the winter weather), it was recommending that generators take the risk that ex post there would be alleviation of the offer cap. In a document[4] released on Tuesday, January 21, PJM stated:

> *PJM will file as soon as practical to seek a retroactive waiver of its system offer cap rule to "make whole" generation resources to their documented costs to the extent such costs exceed the system offer cap. The waiver would seek permission to reimburse affected generation resources through an "uplift" payment. While we*

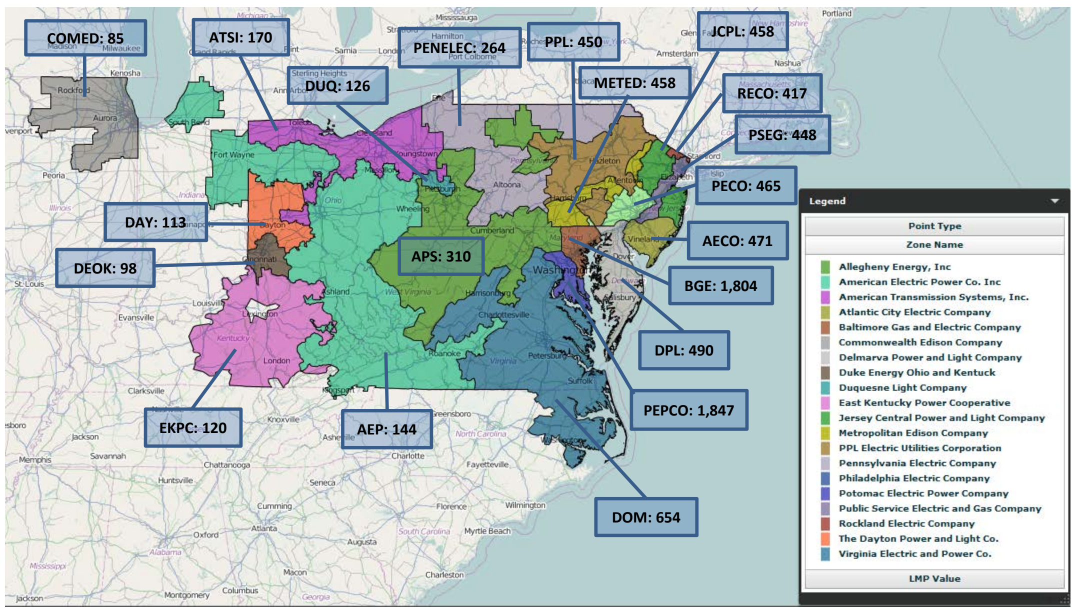
[3] Assumed 22,000 Btu/kWH heat rate, the heat rate used by ISO NE to calculate peakers margins; the heat rate is the rate of converting fuel energy into electrical energy.

[4] http://www.pjm.com/~/media/documents/reports/20140121-cost-based-offers-into-the-day-ahead-energy-market-on-jan-21.ashx

appreciate this predicament leaves some PJM generation capacity resources in an uncertain state, PJM has consulted with counsel and believes the anticipated retroactive waiver request will likely be accepted by the FERC.

The dramatic announcement would not have been necessary if generator offer caps were a function of gas prices times a conversion factor. Such a structure has been in place in other FERC regulated markets in the past. The consequences of providing large economic incentives not to perform create unnecessary risks to grid reliability. It should be noted that the highest administratively set price in the US is $5,000/MWh in Texas, which is scheduled to increase to $9,000/MWh in 2015. Hence, Texas (actually the portion of Texas regulated by the Public Utilities Commission of Texas) would not face such a problem even if gas prices reached the recent record levels seen in the east (which they did not).

Figure 4. PJM Real-Time LMP Energy Pricing ($/MWh) – Wednesday January 22, 2014, 8:00 pm



Source: PJM

During this same period, as seen in the figure above, energy prices in western PJM were much lower, reflecting extreme electric transmission congestion in bringing power east. Thus both the gas and power transmission grids were short of transmission capacity and led to extreme price increases in the eastern Mid-Atlantic. Thus, like the gas transportation bottlenecks that will be discussed below, wholesale price disparity can point to potential new transmission line investments. One additional point to note is that even though New Jersey had similar gas prices to the PEPCO area, its real-time energy pricing did not exceed the offer cap. This is most likely due to a number of factors, some of which are fewer binding transmission constraints.

Cause of High Downstream Natural Gas Prices

As shown in Figure 1 above, there was a wide spread between upstream (supply areas) and downstream (market area) gas prices, indicating that constraints on pipeline capacity were the direct cause of the high delivered gas prices. Gas utilities primarily serve residential and commercial (R/C) gas customers, and so secure firm pipeline transportation contracts roughly equivalent to their customers' projected winter peak day loads to ensure reliability. In contrast, many gas-fired generators, mostly peaking units which only run intermittently, rely on interruptible pipeline capacity.

During summer peaks, when electricity demand is highest, residential and commercial (R/C) demand for natural gas is low, and gas-fired generators usually encounter no problems securing interruptible pipeline capacity. However, during winter cold snaps (such as those we have seen over the past several weeks), the gas utilities need all their firm pipeline capacity to serve their R/C customers, leaving little (if any) interruptible pipeline capacity available to peaking gas generators.

Over the past decade, most new power plants added in the US have been natural gas fired, and already there has been significant retirement of non-gas fired units. As a result, natural gas has comprised an increasingly larger proportion of the energy resource base. Recent and upcoming coal retirements will only increase the need for natural gas for power generation, potentially exacerbating pricing during future winter peaks.

High gas prices in constrained areas are price signals that developers may want to build new pipelines or increase existing pipeline capacity. FERC is responsible for certifying and permitting new pipeline capacity. In order to build a new pipeline or add capacity to an existing pipeline, pipeline companies must demonstrate to FERC that the additional pipeline capacity is economically feasible by securing long-term (generally 10-years or more) firm contracts for the added capacity. This is a high burden and increases the costs and lead-time of new pipeline projects. This is especially difficult in most FERC-regulated ISO markets because nearly all generation capacity is procured for one year only.

Increased Focus on Summer Only Resources

The cold weather highlights the need for careful policy and planning attention to reliability due to changes in resource mix and market rules. The extremely high energy prices in PJM this winter are not only due to the very cold weather, but also reflect decisions made by regulators. As stated in a previous white paper,[5] PJM has increasingly been procuring summer-only resources.

Interruptible load (demand response) accounts for half of PJM's planning reserve margin, and around 80% of that capacity is available only during the summer.[6] Even in the summer, DR is not required to participate in the energy market like generators, and hence is not available to ameliorate energy market price spikes. The price of DR in the most recent capacity auction cleared at $59.37/MW-day, the same price as for generation resources. The prices were the same even though generators can be called to operate during the winter and are required to bid into the energy market, unlike most DR. DR lowers the clearing price of capacity in the market, contributing to the retirement of generators. However these are precisely the resources needed because they can be called in the winter and participate in the energy market. Finally, DR does not have to provide attestation that it will be available when it is needed during the capacity auction even though it is competing with existing generation resources subject to operational testing. FERC proceedings are addressing this issue, but the outcome is uncertain.

Incentives for Reliable Winter Operation

In the absence of appropriate pricing signals during the winter, many choose to not adequately winterize their facilities in order to be available during the coldest periods of the winter. Nearly 40 GW of capacity was unavailable during the polar vortex, fully 20% of capacity in PJM.

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5 http://www.icfi.com/insights/white-papers/2014/commercial-opportunities-and-system-reliability

6 PJM has three types of DR: Limited DR, which can only be dispatched in the summer; extended DR, which can be dispatched from the spring to the fall; and annual DR, which can be called year-round. In the most recent RPM auction (2016/2017), of the nearly 10 GW of DR that cleared, 4.7 GW was limited DR, 3.4 GW was extended DR and only 1.8 GW was annual DR.

Power plants which rely on natural gas are not required to have firm fuel delivery capability, which is mostly required to operate during winter peak periods. Furthermore, administrative mechanisms which estimate the costs of gas fired power plants and set their bid price into the energy market do not include the costs of purchasing firm gas, which is typically estimated as a fixed cost. As a result, this and other mechanisms fail to ensure adequate winter supply. Lastly, the hourly price caps set in markets, which can have a large impact on resource availability, vary widely across markets and as discussed in the earlier ICF white papers may need to be increased. Lastly, estimates of the potential for winter outages turned out to be too low, understating the need for winter supply.

Commercial Consequences

These price spikes represent a significant opportunity for some generators and a cautionary tale for others. Coal units in eastern PJM, where this round of price spikes occurred, most likely earned a large amount of revenue, as their fuel cost was small compared to the soaring gas price. Coal plants would earn around $1,800 in revenue for every MWh they generated when prices were at shortage levels. If the cold snap led to seven days of pricing at similar shortage levels, a typical sized coal plant (1,000 MW) would earn over $302 million. To highlight the magnitude of such earnings, this level of margin roughly equals 30 percent of the capital investment cost of a new combined cycle power plant.

Another winning strategy is a combined cycle plant which has hedged its gas purchases. Combined cycles of similar size to the coal plant above would have made similar profits.

Conversely, un-hedged entities face potentially catastrophic threats to corporate viability. In particular, entities supplying power to retail load and financial hedging parties would be at significant risk. A similar although less drastic cost is the missed opportunity for peakers. A 300 MW combustion turbine peaker that could not dispatch due to winterization oversights missed roughly $91 million in revenues which would be approximately forty percent the investment cost of a new gas peaker.

Conclusions

The system has successfully delivered power in spite of the cold weather, but it has “skated too close to the edge,” resulting in unnecessarily record high prices and strains on the grid. While commercial incentives may result in actions that help eliminate the problems associated with the changes in the gas-power relationship, a series of actions have contributed to exacerbating the problem. Thus, there is likely to remain a combination of commercial opportunities and policy challenges. ICF expects to remain involved in these areas.

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David Gerhardt, a principal with ICF, is an energy analyst with over 20 years of experience in energy economics and energy engineering issues. Most of his work in energy economics has been in areas such as asset valuation, wholesale power litigation, risk management, and PPA negotiations. Mr. Gerhardt is the lead power generation engineer for ICF Consulting's Wholesale Power group. As the lead engineer, he reviews and develops all critical data required by the group, including new power plant cost and performance characteristics by prime mover type, operation and maintenance estimates, forced and scheduled outage rates, uprates, and emission rates. This work has included developing cost estimates for dual fuel retrofits to CCGT machines.

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