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SIMULATION OF THE JANUARY 2014 POLAR VORTEX AND ITS IMPACTS ON INTERDEPENDENT ELECTRIC-NATURAL GAS INFRASTRUCTURE

Edgar Portante
James Kavicky
Brian Craig
Leah Talaber
Stephen Folga

Argonne National Laboratory
9700 South Cass Avenue
Argonne, IL 60439 USA

ABSTRACT

The development of tools that appropriately simulate electric-natural gas interdependencies and their resulting propagation of disturbances within and between systems is a particular need of system operators. The need for such tools is further emphasized by the January 2014 Polar Vortex event, where the response of the electric power and natural gas systems further highlighted the importance of the coordinated assessment of interdependent systems when a large diversion of natural gas to non-electric customers created unexpected consequences in the electric sector. This paper documents ongoing modeling and assessment activities of the Argonne Electric Power−Natural Gas Integrated Model and demonstrates the estimated impacts for this historic disruptive event. This paper presents a description of the Polar Vortex event, the modeling approach and methods used, including the assumptions, data, and modeling platform, and provides simulation results showing agreement with historically reported impacts, in both spatial and quantitative terms, to validate model performance.

1 INTRODUCTION AND MOTIVATION

This paper describes the development and validation approaches applied to an integrated electric power and natural gas modeling environment called the Argonne Electric Power-Natural Gas Integrated Model (AEP-NGIM). Developed by researchers at Argonne National Laboratory, the AEP-NGIM is an integrated linear model that uses a generalized data-centric modeling and simulation framework to combine two existing and proven models *–NGfast,* used for natural gas impact analysis and assessment, and *EPfast,* used for electric system impact analysis and assessment. The generalized simulation framework currently provides the integration mechanism for the electric power and natural gas infrastructure system models, but can effectively integrate all types of critical infrastructure models and permits (1) the integration and automation of the assessment process, including threat and hazard identification and data acquisition; (2) the estimation and projection of impact zones; (3) the simulation of the initial effects on infrastructure assets resulting from an initiating disruptive event; (4) the evaluation of propagating effects within each infrastructure system; and (5) the simulation of the influence of cascading failures across infrastructure systems.

Because of the inherent, cross-cutting interdependencies that further exacerbate the interactions among physical infrastructure systems (e.g., energy, water, communications, etc.), the AEP-NGIM provides an operational and practical example of how the generalized simulation framework can be applied to two energy sector systems. The Data-Centric Modeling and Simulation (DCMS) framework enables a desirable integrated modeling approach that effectively characterizes and couples the interactive behaviors of independent, stovepipe models, thereby providing the opportunity for improved systemic analysis and assessment methods that better represent infrastructure interdependencies.

The application of the simulation framework to the AEP-NGIM begs the second objective of the paper –describe the model validation process of the AEP-NGIM to ensure that the integrated modeling approach provides results that adequately reflect the interdependent behaviors of both infrastructure systems. The outcomes of the 2014 Polar Vortex event are well documented in a report by the North American Electric Reliability Corporation (NERC), which provides a suitable benchmarking scenario that supports the process for desired tool validation purposes (NERC 2014).

Considering these two primary objectives, the paper first presents an overview of this credible historic event, which permits the desired comparison between simulated modeling results and actual system responses. The January 2014 Polar Vortex event provides the ideal case for benchmarking the integrated model, because the detailed NERC report documents event impacts concerning the interdependencies of the electric power and natural gas systems. In the context of interdependent behaviors, this paper then presents an overview of the individual tools comprising the AEP-NGIM and its application of the DCMS framework that permits the coupling of diverse infrastructure modeling capabilities originally expressed as independent models. The paper continues with a description of the modeling and data analysis approach taken to specifically validate AEP-NGIM results with recorded 2014 Polar Vortex events, and concludes by suggesting that the application to this case study may provide a general indication of the unique predicative modeling capabilities offered by the integrated modeling environment comprising the AEP-NGIM.

2 DESCRIPTION OF THE JANUARY 2014 POLAR VORTEX EVENT

In early January of 2014, the Midwest, South Central, and East Coast regions of North America experienced a weather condition known as a polar vortex, where extreme cold weather conditions occurred in locations further south than are typically normal, resulting in temperatures 20−30°F below average. Some areas faced days that were 35°F or more below average temperatures. These temperatures resulted in record-high electric and natural gas demands for particular areas on January 6−8, 2014. During this period, the Midcontinent Independent System Operator (MISO) reported that it exceeded its historic electric winter peak demand for three straight days. The peak loads exceeded the combined non-coincident peaks achieved previously. On January 7, the combined load for the impacted balancing authorities (BAs) was 559,000 megawatts (MW), or about 3% higher than the non-simultaneous historical peak. (NERC 2014).

During the polar vortex, the overall demand for natural gas also increased resulting in a significant amount of natural-gas-fired generation being unavailable because of curtailments of natural gas in the electric sector. Review of natural gas consumption in Illinois using the Energy Information Administration (EIA) 176 data for years 2013, 2014, and 2015 showed that the average natural gas use in January 2014 for the state was higher than in January 2013 by 28% and by 18% when compared to January 2015. Close to 11,000 megawatts (MW) of gas-fired capacity were taken off the grid in the three major NERC regions–the Midwest Reliability Organization (MRO), Reliability First Corporation (RFC), and Southeastern Electric Reliability Council (SERC) owing to fuel supply issues. Specifically, power outages were directly related to the inability of the gas-fired plants to receive natural gas from their provider. (NERC 2014).

Despite the marked increase in electric demand and the substantial reduction in on-line gas-fired capacity resulting from natural gas supply issues, electric grid operators were mostly able to maintain their operating reserve margins and adequately served firm load. By properly and appropriately communicating through the NERC Energy Emergency Alert process using interruptible load, demand-side management tools, and voltage reduction, only one BA was required to shed firm load. The amount shed was less than 300 MW, representing less than 0.5% of the total load for the Eastern Interconnection. However, the regions affected were forced to re-dispatch their generators and significantly alter their operational strategies. (NERC 2014).

3 INTERDEPENDENCIES, THE DCMS FRAMEWORK, AND DEVELOPMENT OF AEP-NGIM

The 2014 Polar Vortex event provides a historically practical example that illustrates the interdependent nature of the natural gas and electric power systems. To properly characterize the interdependent behaviors of these two systems, Argonne subject matter experts evaluated which interactions could be easily represented using publicly available data and yet still yielding meaningful improvements to justify the benefits of a new integrated modeling approach. Researchers adopted the general representation provided in Figure 1, which shows a simplified depiction of the interdependencies between the electric power and natural gas infrastructure systems and supports the development and inclusion of two important constructs of the integrated model: an electric-power-to-natural-gas translator and a natural-gas-to-electric-power translator.

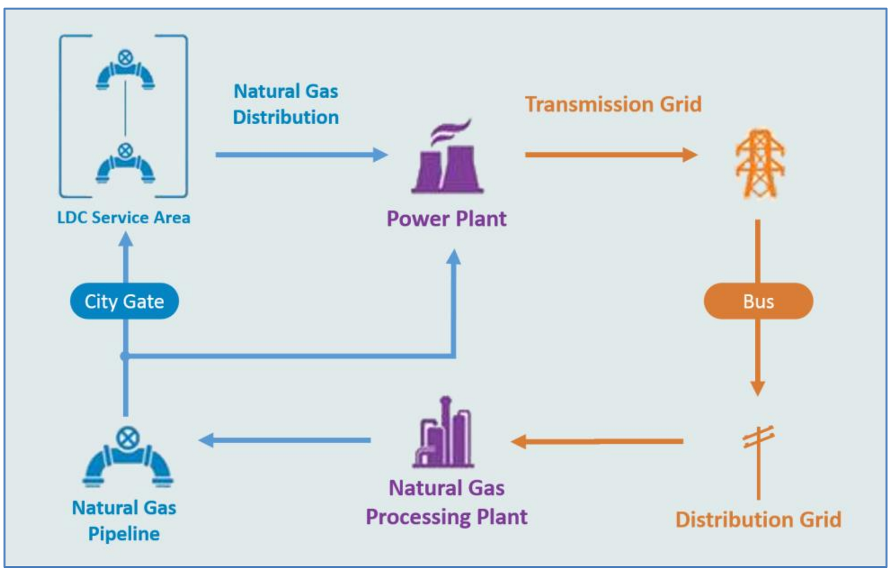


Figure 1: Example of interdependencies between the electric power and natural gas infrastructure.

As shown in Figure 1, both electric power and natural gas systems exhibit a strong interplay, or interdependence, that is well recognized. For example, the electric grid depends on natural gas for fueling its natural-gas-fired power plants. In the other direction, the natural gas supply is dependent on electricity to operate natural gas processing plants (NGPPs) and other supporting system assets (e.g., including electric-driven compressor stations along some pipelines). NGPPs contribute to the natural gas supply by removing impurities and contaminants found in raw natural gas before entering the pipeline transportation system. To further illustrate this point, increased reliance on natural gas as a preferred fuel for electric power generation continues and was further emphasized during recent training and interaction opportunities with the MISO during 2015 (Argonne 2015). In addition, events like the 2014 Polar Vortex further emphasize the close coupling of these two systems. Therefore, the motivation for an approach to integrate electric power and natural gas simulation models is highly supported and contributes to deliberate initiatives that couple the interactions between both infrastructure systems.

In response to this need and that of system operators (e.g., MISO and other utilities), the AEP-NGIM was developed by integrating two existing and proven energy systems simulation models, *EPfast* and

NGfast. However, an easy way to couple and add the necessary modeling components that capture the interdependent characteristics of both infrastructure systems was needed. Thus, the DCMS framework was adopted, which allows current infrastructure models to remain intact, avoiding many code changes, while easily incorporating additional components to improve the characterization and representation of interdependencies between the systems.

The Infrastructure Interdependency Simulation Module within the AEP-NGIM uses the DCMS manager to facilitate the integration of multiple disparate models into one virtual model without introducing major modifications to the original standalone simulation models (Joshi 2011). The DCMS manager, therefore, facilitates the synchronization among integrated simulation models (Figure 2) (Portante et al. 2016).

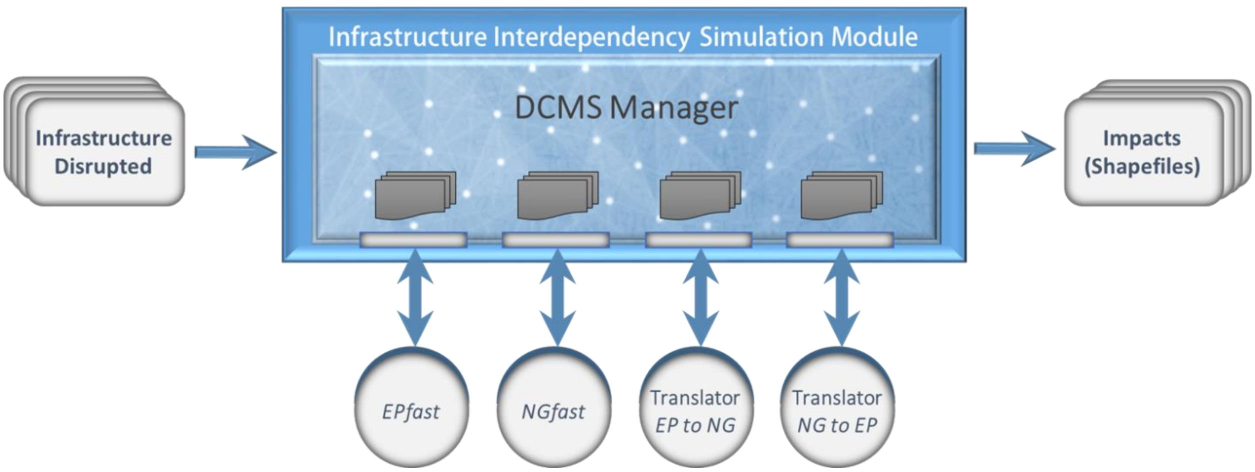


Figure 2: Infrastructure Interdependency Simulation Module of the AEP-NGIM.

The Infrastructure Interdependency Simulation Module is designed based on event-driven programming. It is not procedural; the different models (i.e., simulation and translation) are automatically launched when new inputs are available. The process ends when no new or modified outputs are generated. Being driven by outputs allows the models to cycle until the system stabilizes, until no additional outages occur, or until stopped by the user. The event-based simulation emphasizes the logical unfolding of the events and implies the notion of time. Although the AEP-NGIM only couples electric power and natural gas models, the DCMS framework fully supports the integration of various infrastructure simulation models (e.g., water, communications, etc.). Integration of additional simulation models also requires the development of corresponding translator models to transform the output of each new simulation model to inputs for other simulation models, thereby providing the mechanism for representing the interdependencies among different infrastructure.

Focusing first on the primary models and translators located along the bottom of Figure 2, *EPfast* estimates the area of an electric power outage caused by the loss of electric power system components (Portante et al. 2011). The model explores the possibility of uncontrolled islanding (i.e., an undirected breakup of the grid) caused by successive steady-state line overloads. Such overloads are initially triggered by a major, non-reclosable, line-to-line fault, or simply by the de-energization of a major line due to a natural cause or manmade (deliberate) act. The model estimates the extent (geographic size) and depth (amount of load shed) of the power outage. *EPfast* provides four basic capabilities including standard load flow analysis, contingency analysis, islanding analysis, and power outage estimation.

Given the initial conditions for an event, *EPfast* (1) quantifies the amount of load shed, (2) identifies the affected substations, (3) estimates the territorial dispersal of lost demands, and (4) generates a geographic information system (GIS) outage area for the event. *EPfast* has been successfully used to model the electric power impacts resulting from electric infrastructure disruptions for various Department of

Homeland Security, Department of Energy, Federal Emergency Management Administration, and MISO initiatives (Argonne National Laboratory 2015, and Portante et al. 2014).

NGfast is an impact analysis simulation model developed in 2008 for natural gas systems (Portante, Craig, and Folga 2007). The tool allows for rapid first-stage assessment of the impacts of major natural gas pipeline disruptions at state border points and reductions in flow from import points and production fields. Impacts are measured in terms of extent of gas volume disrupted, states affected, utilities affected, number and type of customers affected, and amount of natural-gas-based capacity affected. *NGfast* has been successfully used to model the natural gas impacts resulting from natural gas infrastructure disruptions for various Department of Homeland Security, Department of Energy, Federal Emergency Management Administration, and MISO initiatives (Portante et al. 2009).

The first translator model (i.e., EP to NG Translator) characterizes what infrastructure assets belonging to the natural gas infrastructure would be impacted by a disruption in the electric power system. This translator applies the electric outage area footprint defined by *EPfast* and determines the affected natural gas assets. It also further characterizes the level of electric power curtailment, and, therefore, projects the operational state of affected natural gas assets that are at risk of being de-energized and removed from service.

The second translator model (i.e. NG to EP Translator) characterizes what infrastructure assets belonging to the electric power infrastructure would be impacted by a disruption in the natural gas system. This second translator applies the natural gas outage area footprint defined by *NGfast* and determines the natural-gas-fired power plants affected by the gas disturbance with electric generation buses in the electric sector.

Located on the left in Figure 2, the list of disrupted infrastructure assets generated by the failure analysis process constitutes the initial disruption conditions and provides the triggers that launch all appropriate infrastructure simulation models (i.e., *EPfast* and *NGfast*) and translator models. Once all models and translators settle and cease additional iterations, impacts to the infrastructure systems are constructed and represented as meaningful shapefiles and other useful information that can be applied to follow-on assessment activities (right side of Figure 2). GIS maps, in the form of Environmental Systems Research Institute (ESRI) shapefiles, show the combined consequences of the natural gas and electric power outages, including the characteristics of load shed and infrastructure disruptions. Other generated HTML-formatted graphics and tabular reports describing natural gas impacts also contribute to follow-on briefing materials. Other summaries, as well as detailed reports (i.e., pre- and post-disruption conditions), communicating natural gas impacts down to the local distribution company (LDC) level are generated and are also available to the end user.

4 VALIDATION METHODOLOGY, ASSUMPTIONS, AND DATA

Two case studies were conducted using an earlier version of the AEP-NGIM and are described in (Portante et al. 2016). Although both case studies illustrated the usefulness of the AEP-NGIM by providing results that reflected plausible and reasonable outcomes resulting from postulated natural and deliberate events, those case studies did not provide a model validation opportunity related to a historical event.

To establish a common definition moving forward in this paper, validation identifies the process of determining the degree to which a simulation model and its associated data are an accurate representation of the real world from the perspective of the intended uses of the model (DOD 2009). Put another way, validation answers the question "Have we built the right model?" (Cook et al. 2005).

The methodology adopted by Argonne is founded on the gas modeling capability of AEP-NGIM that employs flow reduction techniques along the affected natural gas pipelines to simulate the diversion of gas volume from gas-based electric generators to residential customers and other non-electric loads. In essence, this is exactly what occurred during the 2014 Polar Vortex event, because responses to reductions in natural gas supply are directly guided by tariffs and policies that favor the survivability of residential customers and non-electric producer demands. In general, the load-shedding prioritization hierarchy for the natural gas system is sequenced as follows: electric production, industrial, commercial, and residential. Furthermore, active gas-fired plants with an interruptible service contract are shed first, followed by the largest gas-fired plants in the firm service contract category. As a result, curtailments of natural gas supply under serious or extreme conditions are typically projected on natural-gas-fired electric producers.

The methodology, which is also affected by the completeness and availability of pertinent empirical data, follows the general steps of:

a. Identifying all of the gas-fired plants that were forcibly taken off the grid because of fuel issues. The Generator Availability Data System (GADS) from NERC is the most useful data set for this analysis. If plant-level data are not available, the tool uses state-level data to estimate the dispersal of affected capacity in the MISO area.
b. Identifying all of the gas pipelines that supply fuel to the affected power plants determined in Item (a). EIA 860 data are used, as well as other Argonne-developed data to establish the connectivity of the affected gas-fired power plants to gas pipelines (EIA 2017a).
c. Estimating the amount of gas flow reduction through the identified pipelines. A recommended starting point is to determine the equivalent gas flow (in million cubic feet per day [MMcf/D]) associated with the affected gas-fired power plants. This flow is implemented by using appropriate electric power-to-gas flow conversion factors. That number is then used to estimate flow reductions along affected gas pipelines.
d. Running simulation cases using AEP-NGIM assuming flow reductions as determined in Item (c) above.

The effective reconstruction and simulation of a past event almost always requires that a number of sources of recorded information be available and accessible to a simulation team. These informational requirements for the 2014 Polar Vortex case included data on the following:

A. Demand and flow data
    - Natural gas demand during the period of interest at the LDC-level in the MISO area
    - Pre-, during-, and post-event gas flow (in MMcf/D) through the pertinent pipelines
    - Per-bus electrical demand in the MISO area
    - Dispatch schedule of power plants in the MISO area
B. Gas and electric assets participating and dispatched during the event
    - Pipelines affected by the polar vortex
    - Gas-fired power plants affected because of fuel unavailability issues
    - Technical characteristics and gas supply contracts of affected gas-fired plants
    - State-level capacity reduction because of fuel issues
C. Gas-electric model attributes suitable for the simulation
    - Gas-electric model that can simulate the gas diversion from electric to firm non-electric customers
    - Gas-electric model that can identify gas-fired power plants that could be affected by the fuel shortfall because of gas diversion
    - Gas-electric model that can simulate the impact of the removal of gas-fired generation from the electric grid.

Some of the major assumptions made for this study are as follows:

1. Underground gas storage (UGS) facilities are in maximum withdrawal mode with no extra capacity for compensation.
2. Natural gas processing plants (NGPPs) are also in maximum production mode with no extra capacity for compensation.

3. There is no spare capacity from interconnecting pipelines for compensation purposes because most pipelines are assumed loaded to capacity.
4. The gas-fired capacity that was interrupted because of fuel issues during the event is assumed to consist of gas-fired plants having both interruptible and firm service contracts. They are also assumed to consist of directly connected, gas-fired power plants, as well as those indirectly connected via LDCs.
5. The *EPfast* portion of the AEP-NGIM is launched only if the net amount of generating capacity affected is significant enough to cause an outage in the electric sector.

The study had the following limitations due in part to constraints in time and resources:

1. The study would be confined to the MISO area and portions of the Pennsylvania New Jersey Maryland (PJM) Interconnection, LLC region only, depending on the availability of data.
2. The study would simulate only the day with the most severe impact on national grid (i.e., January 8, 2017).
3. The conversion of flow disrupted (MMcf/D) to electric capacity (MW) at connectivity points between gas and electric systems was undertaken by assuming a linear relationship between MMcf/D and MW.
4. The data on actual flow reductions by the pertinent pipelines were not available, and as such, the flow reduction calculations had to be approximated using the MW affected as the initial basis.

The scientific rule that governs the energy flow between the two infrastructure systems is identified by the conversion of the gas flow rate in MMcf/D to electric MW for each gas-fired power plant. The conversion depends on the type of gas-fired power plant:

- For simple-cycle gas turbines with an average net conversion efficiency of 25 percent, one MMcf/D produces about 3.16 MW;
- For combined-cycle gas turbines with an average net conversion efficiency of 65 percent, one MMcf/D produces about 7.6 MW.

Stated another way, a flow reduction of 100 MMcf/D along a natural gas pipeline could potentially affect about 316 to 760 MW of aggregate gas-fired capacity, assuming all 100 MMcf/D is allocated for electric power production without knowing the exact composition of the interconnected power plants. This range defines the lower and upper bounds used in data tables found later in this analysis. The empirical natural gas monthly consumption of individual gas-fired power plants is publicly accessible information and can be obtained from Form EIA-923 (EIA 2017b). This data set is used to refine generator output shaving for the individual at-risk, gas-fired plants.

5 INPUT DATA ANALYSIS AND METHODOLOGY IMPLEMENTATION

Proper analysis and interpretation of recorded historical data are essential in calibrating and setting up the model for simulation.

5.1 Data Analysis

The natural gas demand during the January 2014 Polar Vortex shows the load during the month to be 18–28% higher than the demand in January of the preceding (2013) and ensuing (2015) years. This increase is reflected in the LDC-level loading intensity when EIA 176 is examined in greater detail. For both the residential and commercial sectors, it was noted that there is a marked increase in the use of gas in 2014 for the month of January relative to both January 2013 and January 2015, indicating increased use of gas for heating as a result of the cold weather. The industrial sector exhibited a substantial increase as well relative to both years. The use of gas for electric generation increased dramatically in 2014 relative to 2013 but decreased substantially in 2015 (relative to 2014's high usage levels). The amount of gas diverted from gas-fired power plants to firm non-electric customers can be inferred by examining the capacities taken off of the grid because of fuel issues.

The state-level, gas-based capacity that was forced to be taken off of the grid because of the polar vortex is summarized in Table 1. These data were provided by NERC and were the basis for several NERC reports regarding the polar vortex. It may be noted that the polar vortex has the maximum impact on the electric grid on January 8, 2014, as about 8,660 MW of gas-fired capacity were interrupted across the 20 states.

Table 1: State-level gas-fired power plant capacity that was disrupted because of fuel-related issues.

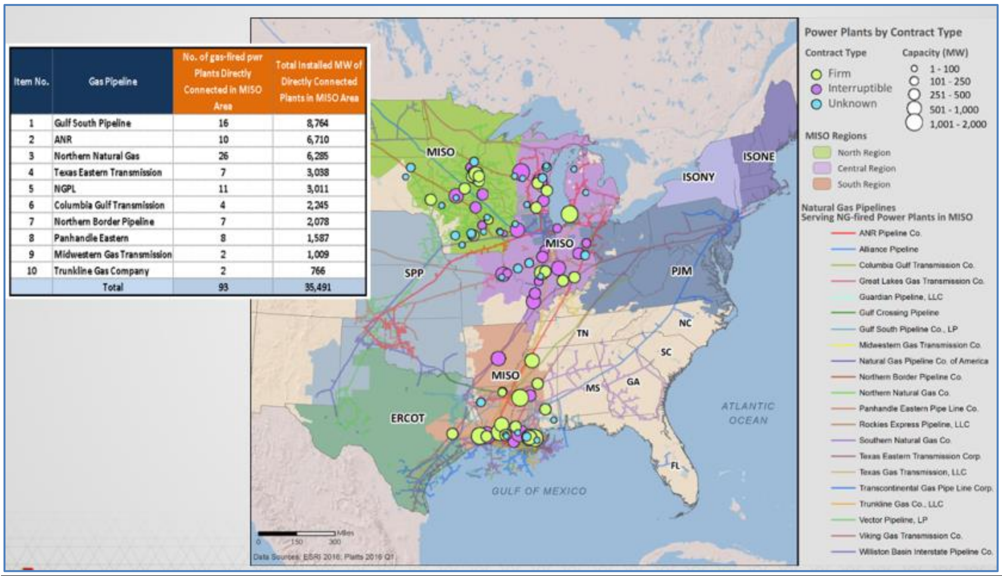
Item No.	States	NERC-ISO	Unplanned Gas-fired Plant Outage Resulting from Fuel Issues (in MW)					
			Start Date (2014)					
			Jan. 4	Jan. 5	Jan. 6	Jan. 7	Jan. 8	Jan. 9
1	NY	NPCC[a]	177.72	-	20.00	96.00	587.82	311.00
2	IL	RFC-MISO	470.00	-	1,692.00	1,014.98	1,298.88	1,668.17
3	CT	NPCC	225.00	-	-	569.00	845.04	-
4	NJ	RFC-PJM	255.80	826.00	-	-	316.00	1,445.80
5	PA	RFC-PJM	1,197.60	-	-	260.30	38.00	849.30
6	MD	RFC-PJM	261.60	322.00	294.00	336.70	230.00	2,201.10
7	VA	SERC	-	161.00	-	152.30	-	152.30
8	MI	RFC-MISO	-	-	1,528.00	764.00	764.00	-
9	WI	MRO-MISO	-	-	-	223.00	-	558.90
10	FL	FRCC[a]	-	-	-	113.00	-	-
11	MS	SERC-MISO	-	-	-	92.00	-	-
12	OH	RFC-PJM	-	-	-	62.90	728.00	507.00
13	MA	NPCC-ISONE	-	-	-	225.60	-	83.00
14	IN	RFC-MISO	-	-	-	59.00	120.00	-
15	AR	SPP[a]	-	-	-	-	1,261.07	-
16	DE	RFC-PJM	-	-	-	-	161.00	-
17	KY	SERC-MISO	-	-	-	-	951.00	-
18	MN	MRO-MISO	-	-	-	-	175.90	-
19	TX	ERCOT	-	-	-	-	393.00	-
20	RI	NPCC-ISONE	-	-	-	-	791.00	90.00
Total All States			2,587.72	1,309.00	3,534.00	3,968.78	8,660.71	7,866.57
Total MISO			470.00	-	3,220.00	2,060.98	3,309.78	2,227.07

[a] ERCOT = Electric Reliability Council Of Texas, Inc.; FRCC = Florida Reliability Coordinating Council; NPCC = Northeast Power Coordinating Council; SPP = Southwest Power Pool.

About 3,309 MW (about 47%) of these outages occurred within MISO. Some of the states affected the most within MISO on January 8 were as follows: Illinois, with 1,298 MW of lost load; Michigan with 764 MW, Kentucky with 951 MW, and Minnesota with 175 MW.

The layouts of the top ten gas pipelines serving MISO with respect to amount of directly connected gas-fired capacity are shown in Figure 3.

The pipelines that were actually affected by the polar vortex and thus experienced substantial diversion of gas were not documented in any publicly available report. However, the pipelines that were most likely to have been affected can be inferred by examining the affected states in Table 1 and then determining the pipelines with the highest levels of gas delivery in those states. A GIS viewer using gas pipeline shapefile layers superimposed on the states' footprints can accomplish this assessment. Using this approach, affected pipelines and the correspondingly affected states are summarized in Table 2.



Item No.	Gas Pipeline	No. of gas-fired pwr Plants Directly Connected in MISO Area	Total Installed MW of Directly Connected Plants in MISO Area
1	Gulf South Pipeline	16	8,764
2	ANR	10	6,710
3	Northern Natural Gas	26	6,285
4	Texas Eastern Transmission	7	3,038
5	NGPL	11	3,011
6	Columbia Gulf Transmission	4	2,245
7	Northern Border Pipeline	7	2,078
8	Panhandle Eastern	8	1,587
9	Midwestern Gas Transmission	2	1,009
10	Trunkline Gas Company	2	766
	Total	93	35,491

Figure 3: The top ten gas pipeline serving MISO (Source: Platts 2014).

Table 2: Major gas pipelines inferred to have experienced significant gas flow diversions.

Item	Gas Pipeline	MISO States Pipeline is Likely to Affect			
		IL	IN	MI	MN
1	Natural Gas Pipeline Company (NGPL)	x			
2	ANR Pipeline Company (ANR)			x	
3	Texas Gas Transmission (TGT)		x		
4	Northern Natural Gas (NNG)				x
5	Panhandle Eastern Pipeline (PEP)		x		

5.2 Calibrating and Setting up AEP-NGIM

To simulate the polar vortex event, it is important that the model be calibrated to approximate the conditions of demand and supply, especially for the gas sector because the gas system supply disruptions provide the initiating events for the electric sector. The *NGfast* portion of the AEP-NGIM defines policy windows that facilitate the implementation and the desired calibration so that the model can account for some features of the historical event. Some of the adjustments that were performed via the AEP-NGIM policy window included:

1. Setting up the policy so that the electric sector experiences the greatest impact.
2. Increasing the electric sector gas consumption by the amount equivalent to the state-level capacity loss.
3. Setting up timing and mode so that the month is set to January and the simulation mode is set to "uncompensated."
4. Setting up pipeline breaks along pertinent pipelines with corresponding specified flow reduction levels. The breaks are chosen at the border of the MISO states that were determined to have experienced losses of gas-fired capacity resulting from fuel issues. A summary of the estimated flow reduction in each affected pipeline is presented in Table 3.

6 SIMULATION RESULTS AND DISCUSSION

Despite the seemingly large number of affected power plants, the regional electric grid experienced merely small problems because of several mitigating measures that were taken, including demand side management, voltage reduction and deployment of spinning reserves, and re-dispatching stand-by generators. Hence, AEP-NGIM's electric model simulator (*EPfast*) was never invoked in the simulation: in total, as reported by NERC, only about 300 MW of load were shed, which is a small percentage of MISO's 120,000 MW of generation output.

Table 3: Estimated initial flow reductions per pipeline to set up the simulation.

Item	Pipeline	Affected Gas Capacity (MW) in MISO				Equivalent Flow Shortfall (MMcf/D)			Flow Reduction at Pertinent Border Point (%)
		IL	IN	MI	MN	Low	High	Average	
1	NGPL	1,298				171	411	291	27
2	ANR			764		101	242	171	23
3	TGT		28			112	269	191	35
4	NNG				175	23	55	39	4
5	PEP		92			16	38	27	2
	Total	1,298	120	764	175	423	1,015	719	26

Table 4 shows a comparison of the amount of gas-fired capacities that were interrupted resulting from the simulation versus the actual recorded values.

Table 4: Comparison of simulated versus actual disrupted gas-fired capacities.

Item	Affected States in MISO	Actual (MW)	Simulated (MW)	Deviation from Actual (%)
1	Illinois	1,298.88	1,158.00	-11%
2	Michigan	764.00	729.00	-5%
3	Indiana	120.00	106.00	-12%
5	Minnesota	175.00	181.00	3%
	Total	2,357.88	2,174.00	-8%

Results show a close agreement between the simulated and the actual values both spatially and quantitatively. The simulation results remain close to the actual values despite approximations made on the identification of the pipelines affected and the amount of flow reductions incurred. Errors or deviations from actual values range from 3-11%.

Given the satisfactory performance of the tool, we have identified some potential applications of the tool: (1) it could serve as the basis for undertaking loss avoidance calculations to justify investment decisions that could upgrade overall system resiliency design and thus harden the system against various threats and hazards; (2) it could be employed as a training tool to improve overall system resiliency by raising the situational awareness of system operators during emergencies and by aiding in the development of emergency response plans; and (3) in the operational arena, it could assist in maximizing mutual benefits between coupled systems while minimizing the risk of cascading disruptions across infrastructure assets.

7 CONCLUSIONS

The January 2014 polar vortex was used to benchmark the performance of Argonne's unique electric-natural gas interdependency simulation tool, AEP-NGIM. The comparison with this event provides the mechanism to credibly validate the model's capacity to appropriately characterize system response against the actual system response recorded for a specific historical event.

Reconstructing a past event for simulation can present challenges, particularly in terms of aligning the assumptions and ensuring the input data's accuracy to properly characterize the pre-event operating state of the electric-gas system in the MISO area. In the absence of complete data describing the event, a methodology that logically inferred the identification of pipelines affected as well as the amount of gas volume diverted from the electric sector was developed and implemented. This step was in combination with using publicly available data approximating the conditions surrounding the polar vortex event.

Results of the simulations using the new tool yielded results that closely resemble the actual impacts observed, in both spatial (geographic extent) and quantitative (amount of MW lost per service territory) terms. The study demonstrated that AEP-NGIM has the capacity to perform as a predictive tool for identifying system vulnerabilities and forecasting, within reasonable error margins, the potential consequences of exploiting such weaknesses caused by natural events. Although the AEP-NGIM simulation results demonstrate an acceptable margin of error with respect to post-event analysis methods privy to unlimited proprietary data, the results nevertheless also validate that tools like AEP-NGIM can bound and quantify the impacts posed by weather on both gas and electric systems. Clearly, there is a need to undertake more tests on AEP-NGIM performance by using other historical events to establish reliability trends as well as more improved calibration procedures to increase the accuracy.

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EDGAR C. PORTANTE is a principal energy systems engineer at Argonne. His research interests include assessments of energy systems, including electric power and natural gas systems. He earned a Master's degree in Electrical and Computer Engineering from the Illinois Institute of Technology, a Master of Management degree from the Asian Institute of Management, and a Master of Science degree in Power Systems Engineering from the University of the Philippines. His e-mail address is ecportante@anl.gov.

JAMES A. KAVICKY works as program manager and Energy Systems Engineer at Argonne. He has provided his expertise on electric power, natural gas, and other infrastructures for reports for the U.S. Department of Homeland Security, U.S. Department of Defense, and U.S. Department of Energy. He has a Ph.D. in Electrical Engineering (Power Systems) from the Illinois Institute of Technology. His e-mail address is kavicky@anl.gov.

BRIAN A. CRAIG is a software engineer at Argonne. His work focuses primarily on the development of computer simulation models for various energy and supply chain systems. Craig earned a B.S. and an M.S. in Computer Science from North Central College in Illinois. His e-mail address is bcraig@anl.gov.

LEAH TALABER works as a technical infrastructure analyst at Argonne. The core of her work involves modeling and geospatial analysis of critical infrastructure in the energy sector. She earned a Master of Urban Planning and Policy from the University of Illinois at Chicago and a B.S. degree in Geography and Geographical Information Sciences (GIS) from Elmhurst College. Her e-mail address is ltalaber@anl.gov.

STEPHEN M. FOLGA is a Senior Manager at Argonne. He is the manager of the Infrastructure Systems branch of the Risk and Infrastructure Science Center at Argonne. He earned a Ph.D. in Gas Engineering and a B.S. degree in Chemical Engineering from the Illinois Institute of Technology. His e-mail address is sfolga@anl.gov.